DOE/BC/14937-8
(OSTI_ID: 3258)

FOSSIL ENERGY

REACTIVATION OF AN IDLE LEASE TO INCREASE HEAVY OIL RECOVERY THROUGH APPLICATION OF CONVENTIONAL STEAM DRIVE TECHNOLOGY IN A LOW DIP SLOPE AND BASIN RESERVOIR IN THE MIDWAY-SUNSET FIELD, SAN JAOQUIN BASIN, CALIFORNIA

Annual Report
June 13, 1996 – June 13, 1997

By
Steven Schamel
Milind Deo
Craig Forster
Creties Jenkins
Doug Sprinkel
Robert Swain

February, 1999

Work Performed Under Contract No. DE-FC22-95BC14937

Energy & Geoscience Institute at the University of Utah
Salt Lake City, Utah

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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DOE/BC/14937-8
Distribution Category UC-122

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Abstract

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Executive Summary

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The 40 ac Pru Fee property is located in the super-giant Midway-Sunset field (Figure 1.1) and produces from the late Miocene Monarch Sand, part of the Monterey Formation. The Midway-Sunset Field was drilled prior to 1890. In 1991 cumulative production from the field reached two billion barrels, with remaining reserves estimated to exceed 695 MMBO. In the Pru Fee property, now held by ARCO Western Energy, cyclic steaming was used to produce 13° API oil. However, the previous operator was unable to develop profitably this marginal portion of the Midway-Sunset field using standard enhanced oil recovery technologies and chose rather to leave more than 3.0 MMBO of oil in the ground that otherwise might have been produced from the 40 ac property. Only 927 MBO had been produced from the property when it was shut-in in 1987. This is less than 15% of the original oil-in-place, which is insignificant, compared to typical heavy oil recoveries in the Midway-Sunset field of 40 to 70%. Target additional recoverable oil reserves from the 40 ac property are 2.9 MMBO or greater. The objective of the demonstration project is to encourage a similar incremental increase in production in all other marginal properties in the Midway-Sunset and adjacent fields in the southern San Joaquin Basin.

A previously idle portion of the Midway-Sunset field, the ARCO Western Energy Pru Fee property, is being brought back into commercial production through tight integration of geologic characterization, geostatistical modeling, reservoir simulation, and petroleum engineering. This property, shut-in over a decade ago as economically marginal using conventional cyclic steaming methods, has a 200-300 foot thick oil column in the Monarch Sand. However, the sand lacks effective steam barriers and has a thick water-saturation zone above the oil-water contact. These factors require an innovative approach to steam flood production design that will balance optimal total oil production against economically viable steam-oil ratios and production rates. The methods used in the Class III demonstration are accessible to most operators in the Midway-Sunset field and could be used to revitalize declining production of heavy oils throughout the region.

Summary of Activity in Budget Period 1

The 40 ac Pru Fee property is located in the super-giant Midway-Sunset field and produces from the late Miocene Monarch Sand, part of the Monterey Formation. The Midway-Sunset Field was discovered prior to 1890. The original 13 wells drilled on the Pru lease in the early 1900's were operated on primary production by Bankline prior to 1959, then Signal Oil Co. until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. Cyclic steaming was used to produce 13 degree API oil from the Pru property until it was shut down in 1986 as uneconomic, at a production rate of less than 10 BOPD. Cumulative recovery of 927 MBO is less than 10% of the original oil in place, as compared to typical heavy oil recoveries in Midway-Sunset of 40 to 70%.

Geology of the Demonstration Site: The Monarch reservoir is present at depths of 1100' to 1400' on the Pru Fee site. The top of the Monarch (Pliocene/Miocene unconformity) dips at less than 10 degrees from northwest to southeast. The net pay isochore indicates that the Monarch pay is thinning from west to east, with an average net pay of about 220'. The thinning pay is caused by the convergence of the unconformity at the top of the Monarch with the oil water contact. Logs show decreasing resistivity with depth, indicating a relatively long transition zone of increasing water saturations in the bottom half of the reservoir. The only other oil bearing formation underlying the Pru Fee site is the Tulare at a depth of 500 feet, which has 2.5 MMBO potential reserves. These reserves may be economically recoverable in the future through recompletions of the Monarch development wells.

Average Monarch reservoir characteristics derived from core and the log model developed for this project are 31% porosity, 2250 md permeability, and 13 gravity oil with 2200 cp viscosity at reservoir temperature of 100 F. The initial average oil saturation in this area is estimated to be 59%. These parameters are all more favorable than what was originally projected at the start of the project, resulting in a significant increase in the estimate remaining oil in place for the Pru lease.

Geological and reservoir characterization: The designated project area, the 40 ac Pru Fee property and a corridor 500 ft in width surrounding the property, contains 143 wells of various ages. Slightly more than 100 of the wells have geophysical log suites available. In the first quarter of the project, those log suites not already in the possession of ARCO Western Energy were assembled. Where only paper logs were available, the logs were digitized. During the second quarter, the remaining suites of paper logs available from diverse sources were digitized and added to the project TerraStation™ database. In addition, during this quarter the core pulled from the new injection well on the site, Pru 101, was analyzed and made available for inspection by the project team. The examination of the core included:

a. Visual core description of lithology, bedding character and oil staining,

b. Routine analyses by Core Laboratories of 246 samples of porosity, permeability and fluid saturations,

c. Thin section analysis of 33 samples, of which 17 were submitted for x-ray diffraction (XRD) analysis,

d. Sieve and laser particle-size analysis conducted on 10 sand samples of a range of visual textures, and

f. A log analysis model of the Monarch Sandstone using PETCOM software to calculate effective porosity, water saturation, non-reservoir volume and permeability.

The Pru 101 well, located near the center of the Pru Fee property, entered the top of the Monarch Sandstone at a depth of 1100 ft, passed through 268 ft of dominantly medium and coarse-grained, oil-stained sand to penetrate the oil-water contact at 1368 ft depth. The base of the Monarch Sandstone was not reached in the well. About 96% of the core recovered from the Monarch Sandstone is highly porous oil-stained sand. The remaining 4% of the core is non-reservoir diatomaceous mudstone and fine sand.

A provisional stratigraphic framework was established using the core description, lithologic analyses, and geophysical logs from the Pru 101 well. Five potentially correlatable stratigraphic markers were identified with this well. These markers are relatively thin (2-10 ft) intervals of fine sand and diatomaceous mudstone that separate thick (30-46 ft) sandstone units. The sand packets each have distinctly different character defined by the style of bedding and/or relative abundance of matrix-supported pebble and boulder beds. The fragments are dominantly subrounded clasts of granite, gneiss and diatomaceous mudstone.

The five stratigraphic markers, the top of the Monarch Sandstone and the oil-water contact have been correlated in well logs across the study area. Using TerraStation, these "tops" have been mapped in a set of seven structure contour maps that serve as the provisional stratigraphic model for the Monarch reservoir at the demonstration site. This stratigraphic model was refined using geostatistical methods.

Petrophysical models developed using Heresim™: Deriving the input parameters needed for fluid flow simulations requires that the 3-dimensional distribution of petrophysical properties be estimated throughout the simulation volume. To this end, a series of petrophysical models are developed for the Pru Fee property and surrounding area using Heresim™, a proprietary code that combines integrated geostatistical modeling and reservoir upscaling capabilities. Geophysical logs from 36 wells, combined with detailed core-derived information from corehole Pru 101, provide the foundation needed to estimate the spatial distribution of facies type, permeability, and porosity. Although a much larger number of wells exist in the vicinity of the Pru Fee, the geophysical log suites needed to estimate permeability and porosity were available only for the 36 wells. A full description of this activity can be found in Chapter 3 of this annual report.

Reservoir Simulation: CMG's STARS thermal simulator was used to predict steamflood production performance at the Pru Fee site. The 3-D model was built as a half-acre symmetry element, cut out of the scaled up version of the geostatistical model. The 3-D permeability distribution model was "history matched" based on the cyclic performance of Pru well 101.

The base case run assumed a two acre inverted 9 spot pattern with continuous injection of 300 BSPD per injector, and cyclic steam of 10,000 BS per producer every two years. Many runs were made to test the sensitivity of various parameters. Production results for the most significant case comparisons, scaled up to the full 8 ac pilot area, suggest that one acre 5 spot development would yield very similar performance as the nine spot configuration. Also the idealized homogeneous case is nearly identical to the geostatistical (stochastic) case, which is not surprising in a half acre model of a relatively homogeneous reservoir.

The most leveraging sensitivity was found in the depth of completions. The base case assumed a 90 ft standoff from the OWC to avoid the higher water saturations of the transition zone. This is compared with the case of a lower completion down to 30 ft above the OWC (Fig. 2.2), which is the traditional completion style used at Kendon and elsewhere in Midway-Sunset field. The performance of the lower completion is much worse than the base case (90 ft standoff) for two reasons. The lower completion case (1) produces out much of the bottom water, allowing the oil to fall to a less recoverable position in the reservoir, while at the same time (2) much of the heat is wasted increasing the temperature of the bottom water, instead of the oil column.

Cyclic Baseline Test Performance: One of the main objectives of Budget Period 1 was to return the Pru Fee property to economic production and establish a productivity baseline with cyclic steaming. By the end of the second quarter 1996, all Pru producers except Pru 101 had been cyclic steamed twice, with each steam cycle being around 10,000 BS per well. No mechanical problems were found in the existing old wellbores.

After the first round of steam cycles it was readily apparent that the new well, Pru 101, was producing much better than the old Pru wells. In fact two of the old producers had no response at all to the first steam cycle. There were several possible explanations for the difference in performance, including: 1) error in steam measurement/allocation, 2) misplacement of steam in the reservoir and 3) formation damage in the older wells.

During the second round of steam cycles, only one well at a time was steamed using one dedicated steam generator to ensure that the measured volume of steam was accurate. Injection tracer surveys were run in each well during the cycle to determine the vertical profile of steam entry into the reservoir. The surveys indicated some variability of vertical profiles from well to well. However, none of the profiles appeared to be particularly unfavorable from the standpoint of heat distribution. There were no obvious small thief zones taking all the steam leaving the rest of the interval unheated.

Temperature logs were run in the temperature observation well TO-1 to determine the heat distribution out in the reservoir away from the producers. No temperature changes were noted in the T.O. well until Pru 101 (the closest producer to T.O. 1) was cyclic steamed, indicating that the injected steam is heating only a limited area around each producer.

Total Pru production following the first steam cycle was about 70 BOPD and 300 BWPD, which was lower than expected, due to poor performance in the older wells. Due to the concerns about steam placement and measurement, the second round of steam cycles were started before production had stabilized from the first cycle. The drop in production during the second cycle is primarily due to producers being taken off line to inject the second steam cycle.

Early production results following the second steam cycle are encouraging. Some old wells, such as producer D-1 are responding better to the second steam cycle. The old wells may have a high near- wellbore skin, as compared to a new well. Time will tell whether this trend of improved production will continue. If it does, this may indicate that the old, abandoned wells may still have the potential to be economic producers as the reservoir heats up with continued injection.

After several years of being shut-in, the existing producers on the Pru Fee property are in reasonable mechanical condition and can, therefore, be utilized as viable producers in whatever development plan we determine is optimum. Production response to cyclic steam is very encouraging in the new producer. However, productivity in the old producers appears to be limited in comparison. Effectively heating the entire reservoir will be the key challenge in economically developing the Pru property.

Rates and Recoverable Reserves: Expected oil rate for the project is based on the 9 spot "no cycles" base case simulation results. The initial rate per new well is estimated at 10 BOPD, ramping up to 29 BOPD (320 BOPD total pilot) in 16 months, flat for 28 months then declining at 40% harmonically to the economic limit. Steam rate is forecasted at 300 BSPD per injector constant for the life of the project. Total peak steam rate is 1200 BSPD for the pilot. The gross capital investment of $1.9 MM will produce 550 MBO ($2.89/BO) with a PW10 of $1,177 M and rate of return of 49%, based on uninflated economics. Recoverable reserves are determined by the economic limit. However, gross expected recoverable reserves are 550 MBO for the 8 ac pilot. Target additional recoverable oil reserves from the 40 ac property are 2.75 MMBO or greater

Steamflood – Review of Alternative Technologies

For the identification of possible applicable technologies, a literature search was completed using the Society of Petroleum Engineers (SPE) Image Library. This technical literature database, on CD- ROM, includes all SPE published papers from the 1950's through 1995. The search included all publications related to recovery of heavy oil using both thermal and non-thermal techniques. Over one hundred papers that appeared to present potentially applicable technologies were reviewed. Of these, about fifty are of interest within the scope of the Pru DOE Class III project. Key technologies are discussed below.

Steamflooding: Economic steamfloods have been performed in heavy oil reservoirs as thin as only 15 feet. Since the reservoir thickness averages at about 275 feet at Pru, this will not be a limitation. Optimum steam flood pattern configuration for a trough reservoir places the injector away from the synclinal axis, a row of producers updip from the injector, and another row of producers near the synclinal axis. The maximum production is obtained by starting the steam flood with an intermediate steam rate (2 bbl per day per acre-foot) and high steam quality (50% or greater), and termination of the steamflood after 5.5 years. These numbers were used to guide technology implementation at Pru. According to Kumar, for confined patterns, a reduction in injection rate after steam breakthrough is beneficial. A linear reduction schedule resulted in the highest discounted net oil production with a lower *Steam/Oil Ratio* (SOR) than a constant injection schedule. Ziegler states that for constant values of well spacing and injection rates, oil recovery from an inverted nine spot pattern was accelerated relative to the five spot pattern. Reservoir simulation sensitivity studies were used to study these aspects at Pru.

Cyclic Steaming: While the lower rates of heat delivered by cyclic steaming may provide a more efficient utilization of injected steam as compared to rapid heating rate of a steamflood on an equivalent cumulative pore volume basis, much lower net cash flows may result in poorer relative economics. Cyclic steaming also is inefficient with low initial reservoir energy (as is the case in Pru). Sequential cyclic steaming is recommended for thick steeply-dipping reservoirs.

Horizontal Wells: Incorporating horizontal wells at the start of a steamflood appears to be a feasible approach for alleviating steam override. The initial productivity can be higher than that of vertical wells, thereby helping to reduce the ultimate number of wells and possibly obviating the need to steam soak producers. Re-entry of vertical wells to drill new horizontal laterals has been successful in restoring productivity of old wells. Physical models have been used in the laboratory to show that a combination of horizontal steam injectors and vertical producers can be used to optimize steamflood performance. Applicability of using horizontal wells at the project site will be explored later in the project.

Project Surveillance: Project surveilance is extremely valuable since project adjustments based on process understanding can steer the project toward economic success. A high density *Temperature Observation Well* (TOW) program is an effective method for analyzing the thermal heating process within the reservoir. Geostatistical mapping of reservoir temperature from temperature logs can be easily applied and provide a more accurate picture than is otherwise available. Good database management can leverage the success of an enhanced oil recovery project. Computer surveillance programs, analytical models and simple numerical simulators are being used to optimize day to day operations. Optimal control theory can be used to determine optimal steamflood operating parameters. Statistical analysis can be used to manage project risk. Most of the above tools are being used in the Pru project.

Reservoirs With Bottom Water: Previous studies suggest that vertical permeability barriers improve recovery in most bottom water reservoirs and also that a horizontal well would overcome water coning problems. Others observed that producing wells farther away from the bottom water will perform better. Inert gas injection can be used to establish a flow path in a cold heavy oil reservoir prior to steamflooding in order to avoid losing heat to bottom water. Bottom water is by far the most serious problem at Pru. Lack of vertical barriers compounds this problem. Specific strategies to address this problem were devised in this project. Optimum well completions were determined to be the answer to the bottom water problems. As the project progresses, specific recommendations will be made.

Initiation of Steam Flood Demonstration

During the period January 19 through April 11, 18 new wells were drilled and completed at the 8 ac pilot near the center of the Pru property. Together with Pru 101, which was drilled in 1995 during the evaluation phase of the project, and eight older wells renovated and put on cyclic production at the start of the project, these wells form a four-fold, nine-spot well pattern. The older wells are B-1, 533, B-3, 12, C-2, C-3, D-1 and D-2. Each injector is surrounded by 8 producers located at the corners and middle edges of a square. Four squares are joined to form a larger square approximately 600 ft by 700 ft, or about 8 ac in size. Along the north edge of the array, a producer is missing from the ideal array between wells 533 and 201. The need to accommodate existing wells into the array has resulted in a departure from an ideal Cartesian spacing of the wells. About half of the producers, those in the interior of the array, are in potential communication with two or more injectors. In addition to the 24 wells in the production array, there are four temperature observation wells, each positioned within 80-180 ft of an injector. One of the temperature observation wells, Pru TO-1, was drilled during the initial phase of the project to monitor cyclic steaming in Pru 101. The other three wells were drilled at the start of the demonstration phase.

In Fall 1995, as the first phase of the project began, eight (8) old production wells were renovated and a new producer, Pru 101, was drilled. After an initial cycle of steaming in the period of October-December 1995, all nine wells were put on production as the cyclic baseline test. The eight old wells are those now included in the pilot array described above. Initial production, except from Pru 101, was generally poor. The wells were steamed again in February-May 1996, and yet again in July-August 1996. In general, rates improved during this period of repeated stimulation and continued production. During the cyclic test period, production averaged for the total group of nine wells about 70 BOD, ranging from 3 to 10 BOD/well for the old wells and about 15 BOD for Pru 101. The average production rate for the nine cyclic producers through the end of 1996 was about 8 BOD/well. The total production rate had begun to decline in the last months of 1996.

In the period January 11 through April 11, 1997 eleven (11) new producers were drilled. Each was primed by steaming in turn during March-May and immediately put into production. The result was nearly an order of magnitude increase in production rate from 50-60 BOD to nearly 400 BOD. The sharp increase in production can, in part, be attributed to the increase in the number of producers from nine to twenty and the fact that the performance of the new wells is consistently better than the old renovated wells. However, the well average jumped from about 8 BOD to nearly 20 BOD with the onset of the pilot steam flood. It anticipated that the performance will continue to improve as the steam chest builds within the demonstration site.

Technology transfer

To present the technical results of the design phase of the project to as broad an audience of California-based operators as possible, a one-day public workshop was held in Bakersfield on December 5, 1996. The site of the public workshop was the Four Points Sheraton Inn, which is very convenient to the offices of most of the companies then operating in the Midway-Sunset and other fields in the southern San Joaquin Basin. The program covered the geology, lithologic characterization, geostastical modeling, and reservoir simulation of the Pru demonstration site. In addition, the results of the cyclic baseline testing and the plans for the demonstration phase were presented. To supplement the oral presentations, poster displays and segments of the Pru 101 core were available for inspection during the coffee/lunch breaks and at the end of the workshop.

There were about 55 registrants for the public workshop representing nearly all of the significant operators, large and small, in the Midway-Sunset Field. Jerry Casteel and Viola Rawn-Schatzinger attended representing the DOE National Petroleum Technology Office. Project team members presenting at the workshop were Steven Schamel, Creties Jenkins, Doug Sprinkel, Craig Forster, Milind Deo and Bob Swain.

By invitation, members of the project team participated in the DOE-sponsored *Fourth International Reservoir Characterization Technical Conference* held in Houston, Texas, March 2-4, 1997. The paper entitled "Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam drive technology in the Midway-Sunset Field, San Joaquin Basin, California" was published in the conference proceedings and presented as a poster.

At the 1997 annual convention of the American Association of Petroleum Geologists (AAPG) in Dallas, Texas, April 6-9, the project team presented an invited paper in the session *Results of Joint DOE/Industry Programs*. The poster paper entitled "Enhanced oil recovery in the Midway-Sunset Field, San Joaquin Basin, California: A DOE Class III Oil Technology Demonstration Project" summarized the purpose of the project and the technical results to date. By invitation, the same poster paper was presented at the annual meeting of the Pacific Section of the AAPG in Bakersfield, California in mid-May, 1997.

Chapter 1

Introduction

Objective

This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the *reservoir characterization phase* of the project. During the *demonstration phase* begun in January 1997, a continuous steamflood enhanced oil recovery was initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

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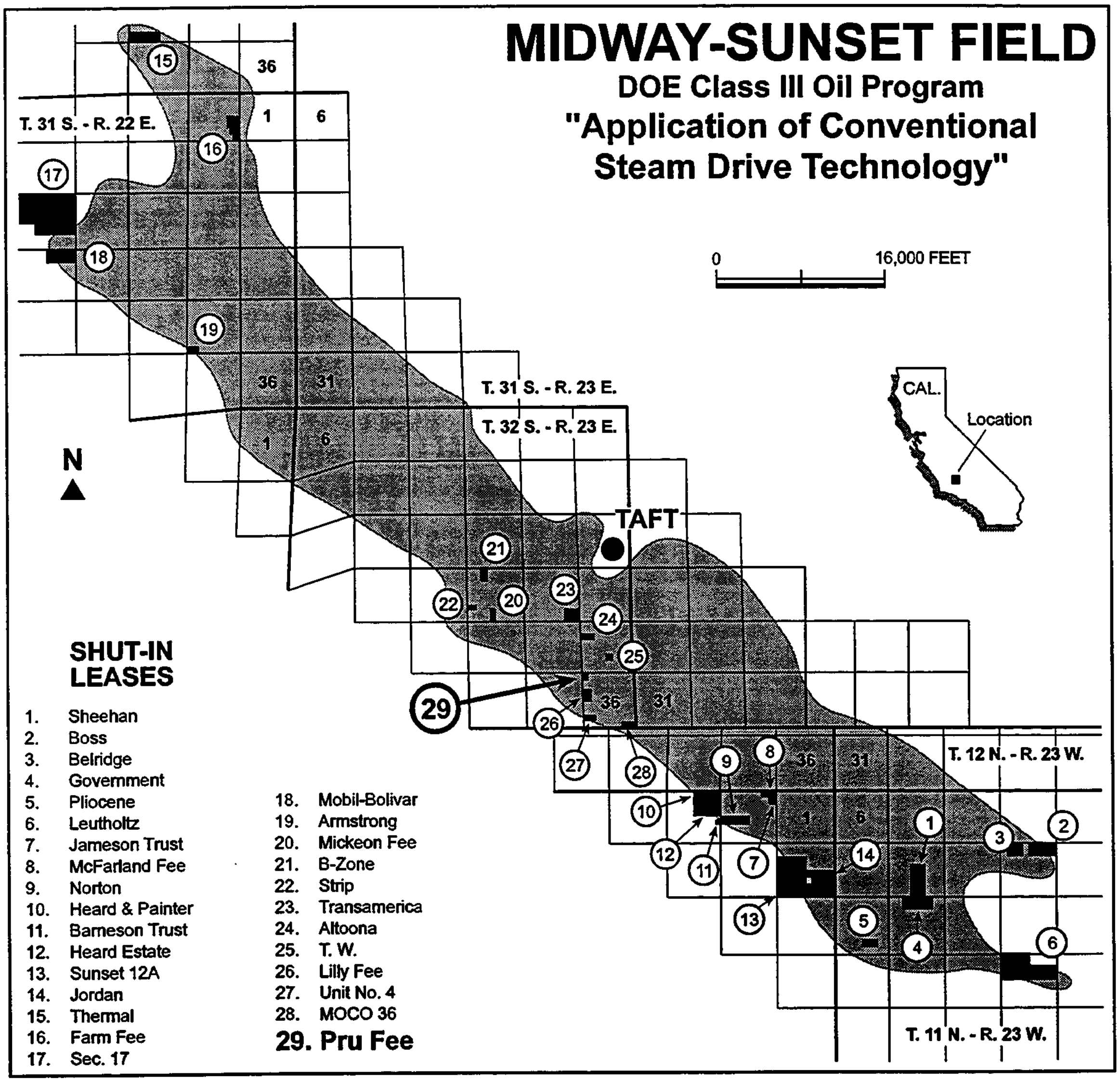

Figure 1.1: Index map of the Midway-Sunset field showing location of the Pru Fee property and other shut-in leases.

Project Organization

This Class III Oil Technology Demonstration, which is sponsored with matching funds from the U.S. Department of Energy, Office of Fossil Fuels, involves the collaboration of three separate organizations:

- the *University of Utah*, represented by the Energy & Geoscience Institute, serving as the Prime Contractor and project coordinator

- *ARCO Western Energy*, the owner and operator of the Pru Fee property
- the *Utah Geological Survey*, responsible for technology transfer and geologic evaluation.

The project team members and their particular areas of responsibility to the project are:

Energy & Geoscience Institute at the University of Utah (Salt Lake City, UT)
- Dr. Steven Schamel - project manager and research coordinator
- Dr. Craig Forster - reservoir characterization and geostatistics

Department of Chemical and Fuels Engineering, University of Utah
- Dr. Milind Deo - reservoir characterization and simulation
- Ms. Hongmei Huang - geostatistics and reservoir simulation

ARCO Western Energy (Bakersfield, CA)
- Mr. Robert Swain - petroleum engineering and site management
- Mr. Mike Simmons - petroleum geology and reservoir characterization

Utah Geological Survey (Salt Lake City, UT)
- Dr. Doug Sprinkel - stratigraphic analysis and reservoir characterization
- Dr. Roger Bon - technology transfer

ARCO Exploration and Production Technology (Plano, TX)
- Dr. Creties Jenkins - advisor for stratigraphy and reservoir characterization

Authors of this annual report are: Project team (Chapter 2), Craig Forster and Milind Deo (Chapter 3), Robert Swain and Milind Deo (Chapter 4), Steven Schamel (Chapters 5 and 6). The report was edited and assembled by Steven Schamel.

Project Activities in Year 2

A variety of activities have been carried out during the period July 1996 through June 1997 leading to completion of the program for Budget Period 1 in December 1996, application for project continuation, and initiation of Budget Period 2.

1. Completion of petrophysical modeling of the Monarch Sand reservoir at the Pru pilot site using Heresim™ geostatistical software. This activity is described in Chapter 3.

2. Review of steamflood and alternative EOR technologies; presented in Chapter 4.

3. Reservoir simulation of the Pru pilot site and the use of the simulations together with the review of alternative technologies to recommend the best-practice procedures to adopt for initiation of the demonstration. This activity and the recommended procedures are described in Chapter 2.

4. Presentation of the results of the *characterization phase* (Budget Period 1) of the project at a full-day public workshop held in Bakersfield, California on December 5, 1996. There were 55 registrants at the workshop representing nearly all of the significant operators in the Midway-Sunset field. Additional information on this and other technology transfer activities is presented in Chapter 6.

5. Development, submittal and approval of the Continuation Application to continue the project into Budget Period 2 (BP-2) . The Statement of Work (SOW) for BP-2 accompanying the Continuation Application is presented as Appendix 1.

6. Initiation of the *demonstration phase* (BP-2) early in 1997 during which time 18 new wells were drilled and completed and the steamflood pilot was begun. These activities are described in Chapter 5.

Chapter 2

Summary of Activity in Budget Period 1

General Statement

This project reactivates ARCO's idle Pru Fee lease in the Midway-Sunset field, California and conducts a continuous steamflood enhanced oil recovery demonstration aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming is being used to reestablish baseline production within the *reservoir characterization phase* of the project. During the *demonstration phase* begun in January 1997, a continuous steamflood enhanced oil recovery will be initiated to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained in this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to optimal commercial production; (2) to accurately describe the reservoir and recovery process; and (3) to convey the details of this activity to the domestic petroleum industry, especially to other producers in California, through an aggressive technology transfer program.

The 40 ac Pru Fee property is located in the super-giant Midway-Sunset field and produces from the late Miocene Monarch Sand, part of the Monterey Formation. The Midway-Sunset Field was discovered prior to 1890. The original 13 wells drilled on the Pru lease in the early 1900's were operated on primary production by Bankline prior to 1959, then Signal Oil Co. until 1969, when infill drilling and cyclic steaming was initiated by Tenneco. Cyclic steaming was used to produce 13 degree API oil from the Pru property until it was shut down in 1986 as uneconomic, at a production rate of less than 10 BOPD. Cumulative recovery of 927 MBO is less than 10% of the original oil in place, as compared to typical heavy oil recoveries in Midway-Sunset of 40 to 70%.

ARCO acquired the lease in 1988. The property is located in the Midway-Sunset field in the NW1/4, NW1/4 of Section 36, T32S, R23E, MDBM, adjacent to the Kendon lease. After returning the lease to production and drilling two additional wells in 1995 (Pru 101 producer & TO-1), there are currently 9 active producers, 1 T.O. well, and 10 shut-in producers on the lease which have not yet been abandoned. Pru production goes through an existing pipeline to a wet oil metering facility on the Kendon lease, and is then processed through the Kendon tank facility. Clean oil volumes are allocated back to the appropriate leases. Casing vent gases will also be taken to the Kendon lease for processing at compressor site K-1. The future steam injection patterns would extend the existing Monarch steamflood on the Kendon lease eastward across Pru and Pru A. The Pru DOE project is focused on determining the feasibility of the expansion by detailed reservoir analysis (Budget Period 1), and a 4 pattern steamflood pilot (Budget Period 2) within the cross hatched area.

Geology of the Demonstration Site

The Monarch reservoir is present at depths of 1100' to 1400' on the Pru Fee site. The top of the Monarch (Pliocene/Miocene unconformity) dips at less than 10 degrees from northwest to southeast. The net pay isochore indicates that the Monarch pay is thinning from west to east, with an average net pay of about 220'. The thinning pay is caused by the convergence of the unconformity at the top of the Monarch with the oil water contact. Logs show decreasing resistivity with depth, indicating a relatively long transition zone of increasing water saturations in the bottom half of the reservoir. The only other oil bearing formation underlying the Pru Fee site is the Tulare at a depth of 500 feet, which has 2.5 MMBO potential reserves. These reserves may be economically recoverable in the future through recompletions of the Monarch development wells.

Average Monarch reservoir characteristics derived from core and the log model developed for this project are 31% porosity, 2250 md permeability, and 13 gravity oil with 2200 cp viscosity at reservoir temperature of 100 F. The initial average oil saturation in this area is estimated to be 59%. These parameters are all more favorable than what was originally projected at the start of the project, resulting in a significant increase in the estimate remaining oil in place for the Pru lease.

Detailed geological characterization was one of the primary objectives of Budget Period 1. By taking new core, and integrating all existing core and modern log information, we believe we have a much better understanding of the geology and its role in reservoir performance. Thinning net pay, low dip, increasing reservoir heterogeneity, and an underlying aquifer were originally suspected to be the main problems which inhibited past performance at Pru. Of these, the bottom water and associated transition zone appears to be the most leveraging factor, as discussed later in the simulation results. The reservoir is actually much more homogeneous than expected, which in turn makes the thinning pay and low dip of less concern.

The geostatistical models built for the Pru Fee site and surrounding area predict the 3D distribution of lithofacies and permeability. Based on these models, the Pru property has more desirable coarse and medium grained sand as compared to Kendon, which tends to be more pebbly. The reservoir is relatively homogenous with only one significant permeability barrier indicated within the top half of the reservoir. The details of the stratigraphic and geostatistical modeling are presented below.

Geological and reservoir characterization

The designated project area, the 40 ac Pru Fee property and a corridor 500 ft in width surrounding the property, contains 143 wells of various ages. Slightly more than 100 of the wells have geophysical log suites available. In the first quarter of the project, those log suites not already in the possession of ARCO Western Energy were assembled. Where only paper logs were available, the logs were digitized. During the second quarter, the remaining suites of paper logs available from diverse sources were digitized and added to the project TerraStation™ database. In addition, during this quarter the core pulled from the new injection well on the site, Pru 101, was analyzed and made available for inspection by the project team. The examination of the core included:

a. Visual core description of lithology, bedding character and oil staining,

b. Routine analyses by Core Laboratories of 246 samples of porosity, permeability and fluid saturations,

c. Thin section analysis of 33 samples, of which 17 were submitted for x-ray diffraction (XRD) analysis,

d. Sieve and laser particle-size analysis conducted on 10 sand samples of a range of visual textures, and

f. A log analysis model of the Monarch Sandstone using PETCOM software to calculate effective porosity, water saturation, non-reservoir volume and permeability.

The Pru 101 well, located near the center of the Pru Fee property, entered the top of the Monarch Sandstone at a depth of 1100 ft, passed through 268 ft of dominantly medium and coarse-grained, oil-stained sand to penetrate the oil-water contact at 1368 ft depth. The base of the Monarch Sandstone was not reached in the well. About 96% of the core recovered from the Monarch Sandstone is highly porous oil-stained sand. The remaining 4% of the core is non-reservoir diatomaceous mudstone and fine sand.

A provisional stratigraphic framework was established using the core description, lithologic analyses, and geophysical logs from the Pru 101 well. Five potentially correlatable stratigraphic markers were identified with this well. These markers are relatively thin (2-10 ft) intervals of fine sand and diatomaceous mudstone that separate thick (30-46 ft) sandstone units. The sand packets each have distinctly different character defined by the style of bedding and/or relative abundance of matrix-supported pebble and boulder beds. The fragments are dominantly subrounded clasts of granite, gneiss and diatomaceous mudstone.

The five stratigraphic markers, the top of the Monarch Sandstone and the oil-water contact have been correlated in well logs across the study area. Using TerraStation, these "tops" have been mapped in a set of seven structure contour maps that serve as the provisional stratigraphic model for the Monarch reservoir at the demonstration site. This stratigraphic model was refined using geostatistical methods.

Petrophysical models developed using Heresim™

Deriving the input parameters needed for fluid flow simulations requires that the 3-dimensional distribution of petrophysical properties be estimated throughout the simulation volume. To this end, a series of petrophysical models are developed for the Pru Fee property and surrounding area using Heresim™, a proprietary code that combines integrated geostatistical modeling and reservoir upscaling capabilities. Geophysical logs from 36 wells, combined with detailed core-derived information from corehole Pru 101, provide the foundation needed to estimate the spatial distribution of facies type, permeability, and porosity. Although a much larger number of wells exist in the vicinity of the Pru Fee, the geophysical log suites needed to estimate permeability and porosity were available only for the 36 wells. A full description of this activity can be found in Chapter 3 of this annual report.

Developed by the Institute Francais Du Petrole (IFP) and collaborators (ARMINES and BEICIP-FRANLAB), Heresim™ is distributed in the United States by Geomath. The code is specifically designed to foster the collaboration of sedimentologists, geostatisticians, reservoir geologists and reservoir engineers in building integrated reservoir models. Several features of the code reflect the obvious desire of the programmers to allow subjective geological inference to be combined with geostatistical modeling. For example, vertical proportion curves and variograms provide a graphical synthesis of the distribution of sedimentary units that can be used, in turn, to design petrophysical models that provide a best fit to the geological environment.

The petrophysical models are computed within a domain that surrounds the reservoir simulation volume and contains data derived from wells drilled in adjacent leases. The upper boundary of the modeling domain, and reservoir top, is the top of the Monarch Formation. An contour map of this surface is computed with Heresim™ using log picks from the 36 wells. The bottom of the modeling domain is less easily defined because many wells terminate before penetrating the oil-water contact. Yet, the high permeability of the Monarch Formation below the oil-water contact requires that we include a portion of the aquifer that underlies the oil-saturated zone in the reservoir simulations. As a first approximation, the geometry of surface S3 is assumed to provide a reasonable geometry for the bottom boundary of the petrophysical model. Thus, the bottom boundary of the petrophysical model parallels surface S3 at a depth of 61 m [200 feet] below S3.

During geological analysis of the reservoir data it became apparent that S3 forms an important surface separating two major lithotypes. Thus, separate petrophysical models are computed for the Upper and Lower lithotypes. Probability distribution functions that reflect the character of permeability and porosity within each lithotype are estimated using univariate statistics derived from corehole Pru 101. Spatial variability in facies type, characterized using both variograms and vertical proportion curves, provides a basis for estimating the spatial distribution of permeability and porosity. Petrophysical models are computed using a 3-dimensional gridded volume with Dx = Dy = 9m [27 feet]. Using this approach a total of 220 computational layers are defined that extend laterally throughout the model domain.

Heresim™ uses an indicator approach to develop a petrophysical model. First, facies distributions are interpolated throughout the 3-dimensional modeling domain. Second, permeability and porosity are assigned to individual gridblocks within each facies type using a probabilistic method. Using the indicator approach requires that facies distributions be defined using geophysical log suites collected at each of the 36 wells and augmented with core data from wells Kendon 405, Pru 533, and Pru 101. The distribution of facies types identified in Pru 101 using log-based criteria compare favorably with the facies types observed in the Pru 101 drillcore. The vertically gridded well data provide a foundation for computing the facies-based variograms and vertical proportion curves used by Heresim™ to interpolate facies distributions throughout the model domain. A vertical proportion curve is a stacked bar diagram that represents the vertical distribution of the percentages of all the facies found within a specific lithotype. Vertical proportion curves provide a valuable tool for summarizing and quantifying geological information contained in the facies descriptions. The curves show that coarse/granule sand dominates all other lithotypes with muddy facies comprising only a small proportion of the reservoir.

Univariate statistics are computed using values of porosity and permeability derived from core plugs collected in P 101. Because this well is located in the middle of the region of interest, these data form an important basis for computing and conditioning the petrophysical models. The statistics obtained for Facies 1 (pebbley sand), 2 (coarse/granule sand), and 3 (medium sand) are summarized in Table 2. Insufficient data are available to evaluate the character of muddy Facies 4.

Table 2.1: Univariate Statistics for Porosity and Permeability from Pru 101

	Facies 1 Pebbley		Facies 2 Coarse/Granuler		Facies 3 Medium	
	Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)
Min.	24.9	748	26.2	770	28.6	185
Max.	32.9	4134	36.2	6000	43.6	5268
Mean	28.6	2277	31.1	3301	33.5	2004
Std. Dev.	2.2	1039	1.8	2702	2.6	1154
No. Points	21	21	120	120	66	66

Several features of the statistics summarized in Table 2.1 are of interest. First, mean porosities increase from 28.6% to 33.5% with decreasing grainsize (from pebbley to medium sand). Second, there is no corresponding trend in the permeability values which are consistently very high in these sandy facies (about 200 to 6000 mD). Third, the permeability distributions are better approximated as normal, rather than log-normal, distributions.

The variogram models and vertical proportion curves described in the previous sections provide the input needed for Heresim™ to compute a series of realizations for the 3-dimensional facies structure. This process involves using a Gaussian simulation approach to compute facies indicator functions. Each facies indicator function forms a particlar realization of a random set of facies assignments. Each realization is one of a series of equi-probable realizations. Each new realization is generated by varying only the numerical seed used in the geostatistical simulations. The simulation results are explicitly conditioned by the well data and constrained to produce vertical proportion curves that resemble the ones computed using the well data.

Upscaling is required to assign representative values of permeability and porosity within the 6 by 6 reservoir simulation model domain. In this study, we need only upscale in the vertical direction because the reservoir simulation grid matches the 9 m by 9 m petrophysical simulation grid. In constructing a computationaly affordable model we elected to reduce the 220 layer petrophysical grid to a 20 layer reservoir simulation grid. A simple arithmetic averaging method is used to upscale porosity. Permeability is vertically averaged using a three-step algebraic method.

The Heresim™ code provides a straightforward environment for constructing geologically plausible realizations of the permeability and porosity structure at the Pru Fee. A fine-scale geostatistical model of four facies types is developed using an indicator approach constrained by geophysical logs from 36 wells and core data from 3 wells. Permeability and porosity are assigned within each facies type using probability distribution functions derived from core data collected in a recently drilled well located in the middle of the model domain. Even prior to upscaling the petrophysical model it is clear that relatively homogeneous models are constructed for each of eight realizations. The upscaled 20 layer models form the basis for fluid flow simulations used to evaluate the production potential of the Pru Fee.

Reservoir Simulation

CMG's STARS thermal simulator was used to predict steamflood production performance at the Pru Fee site. The 3-D model was built as a half acre symmetry element, cut out of the scaled up version of the geostatistical model. The 3-D permeability distribution model was "history matched" based on the cyclic performance of Pru well 101.

The base case run assumed a two acre inverted 9 spot pattern with continuous injection of 300 BSPD per injector, and cyclic steam of 10,000 BS per producer every two years. Many runs were made to test the sensitivity of various parameters. Production results for the most significant case comparisons, scaled up to the full 8 ac pilot area, suggest that one acre 5 spot development would yield very similar performance as the nine spot configuration. Also the idealized homogeneous case is nearly identical to the geostatistical (stochastic) case, which is not surprising in a half acre model of a relatively homogeneous reservoir.

The most leveraging sensitivity was found in the depth of completions. The base case assumed a 90 ft standoff from the OWC to avoid the higher water saturations of the transition zone. This is compared with the case of a lower completion down to 30 ft above the OWC (Fig. 2.2), which is the traditional completion style used at Kendon and elsewhere in Midway-Sunset field. The performance of the lower completion is much worse than the base case (90 ft standoff) for two reasons. The lower completion case (1) produces out much of the bottom water, allowing the oil to fall to a less recoverable position in the reservoir, while at the same time (2) much of the heat is wasted increasing the temperature of the bottom water, instead of the oil column.

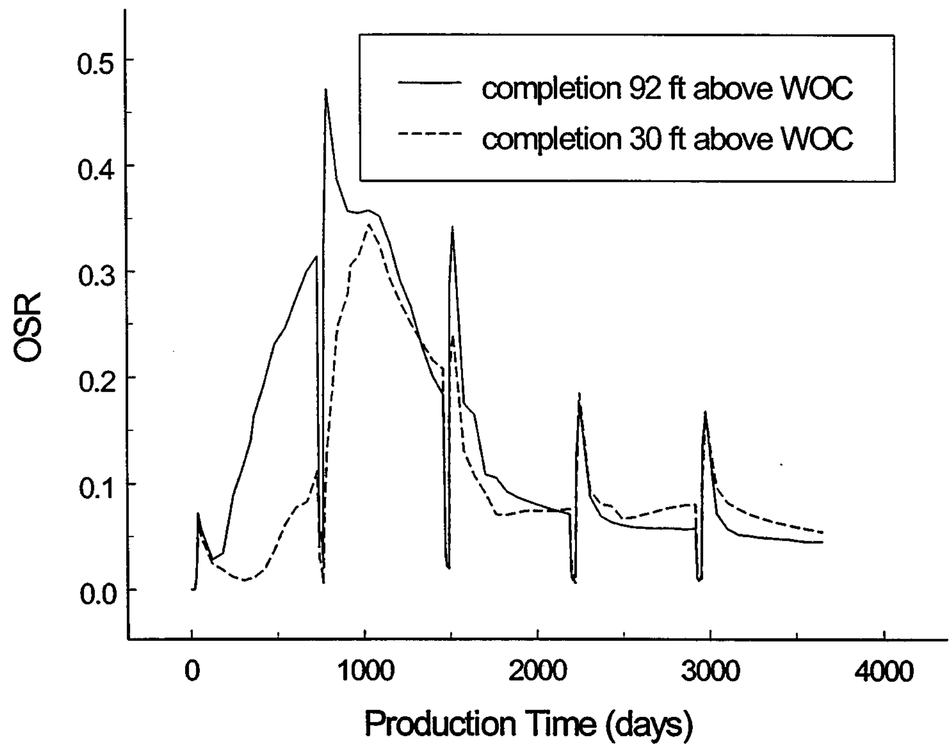

Figure 2: Predicted oil-steam ratio (OSR) for a well completed with a 92 ft standoff above the OWC versus a well with a 30 ft standoff. The simulation is for a 0.5 ac spacing in an inverse 9-spot array with injection rate of 0.5 BS per ac ft/day.

The modeling also indicates that about the same overall production performance can be obtained *without* cyclic steaming the producers. As it is much easier to model the economics for the "no cycles" case, the base case with "no cycles" is used as the production forecast for the expected case economic evaluation. The oil, steam and OSR forecasts were developed for this case.

Table 2.2
Pru Demonstration Site Reservoir Simulation Results

CASE	CUME MBO	%ROIP	CUME MBS	OSR
9 Spot Base Case	630	0.25	5004	0.13
5 Spot	645	0.26	4764	0.14
9 Spot Homogeneous	621	0.25	5004	0.12
9 Spot 2an Realization	631	0.25	5004	0.13
9 Spot 3rd Realization	624	0.25	5004	0.12
9 Spot w/ 2400 BSPD	750	0.30	9387	0.08
9 Spot Side Wells Delayed	535	0.21	4940	0.10
9 Spot Lower Completions	476	0.19	5004	0.10
9 Spot No Cycles	608	0.24	4384	0.14

Table 2.2 summarizes the simulation results for the cases discussed above, as well as a few of the other cases run. Note that none of the other geostatistical realizations yielded significantly different results. The case for doubling injection rate resulted in increased recovery, but the incremental production was uneconomic due to a very low OSR. Another case in which drilling of the side pattern wells was delayed decreased both the recovery and the OSR.

Cyclic Baseline Test Performance

One of the main objectives of Budget Period 1 was to return the Pru Fee property to economic production and establish a productivity baseline with cyclic steaming. By the end of the second quarter 1996, all Pru producers except Pru 101 had been cyclic steamed twice, with each steam cycle being around 10,000 BS per well. No mechanical problems were found in the existing old wellbores.

After the first round of steam cycles it was readily apparent that the new well, Pru 101, was producing much better than the old Pru wells. In fact two of the old producers had no response at all to the first steam cycle. There were several possible explanations for the difference in performance, including: 1) error in steam measurement/allocation, 2) misplacement of steam in the reservoir and 3) formation damage in the older wells.

During the second round of steam cycles, only one well at a time was steamed using one dedicated steam generator to ensure that the measured volume of steam was accurate. Injection tracer surveys were run in each well during the cycle to determine the vertical profile of steam entry into the reservoir. The surveys indicated some variability of vertical profiles from well to well. However, none of the profiles appeared to be particularly unfavorable from the standpoint of heat distribution. There were no obvious small thief zones taking all the steam leaving the rest of the interval unheated.

Temperature logs were run in the temperature observation well TO-1 to determine the heat distribution out in the reservoir away from the producers. No temperature changes were noted in the temperature observation well until Pru 101 (the producer closest to TO-1) was cyclic steamed, indicating that the injected steam is heating only a limited area around each producer.

Temperature logs over time show that the only heating observed in the Monarch reservoir is at the top of the reservoir. This implies that although the vertical heat distribution is favorable at the producers, the heat quickly migrates to the top of the reservoir, leaving most of the oil unheated. This may be due to the thin partially depleted interval we observed at the top of the Monarch in the whole core and open hole logs taken from Pru 101. Even a small gas saturation in the reservoir likely would provide a "path of least resistance" for preferential flow of steam because of more favorable relative permeability as compared to the heavy oil saturated sand.

Another significant temperature increase was noted in the temperature observation well in the Tulare reservoir, at a depth of 500 feet. This indicates that part of the heat required to mobilize oil in the Monarch reservoir is actually leaking up into the Tulare. We currently suspect that this is due to old wellbores which were not properly abandoned several years ago. This is a problem which must be studied further and remedied.

Total Pru production following the first steam cycle was about 70 BOPD and 300 BWPD, which was lower than expected, due to poor performance in the older wells. Due to the concerns about steam placement and measurement, the second round of steam cycles were started before production had stabilized from the first cycle. The drop in production during the second cycle is primarily due to producers being taken off line to inject the second steam cycle.

Early production results following the second steam cycle are encouraging. Some old wells, such as producer D-1 are responding better to the second steam cycle. The old wells may have a high near- wellbore skin, as compared to a new well. Time will tell whether this trend of improved production will continue. If it does, this may indicate that the old, abandoned wells may still have the potential to be economic producers as the reservoir heats up with continued injection.

After several years of being shut-in, the existing producers on the Pru Fee property are in reasonable mechanical condition and can, therefore, be utilized as viable producers in whatever development plan we determine is optimum. Production response to cyclic steam is very encouraging in the new producer. However, productivity in the old producers appears to be limited in comparison. Effectively heating the entire reservoir will be the key challenge in economically developing the Pru property.

Rates and Recoverable Reserves

Expected oil rate for the project is based on the 9 spot "no cycles" base case simulation results. The initial rate per new well is estimated at 10 BOPD, ramping up to 29 BOPD (320 BOPD total pilot) in 16 months, flat for 28 months then declining at 40% harmonically to the economic limit. Steam rate is forecasted at 300 BSPD per injector constant for the life of the project. Total peak steam rate is 1200 BSPD for the pilot. The gross capital investment of $1.9 MM will produce 550 MBO ($2.89/BO) with a PW10 of $1,177 M and rate of return of 49%, based on uninflated economics. Recoverable reserves are determined by the economic limit. However, gross expected recoverable reserves are 550 MBO for the 8 ac pilot. Target additional recoverable oil reserves from the 40 ac property are 2.75 MMBO or greater.

Chapter 3

Petrophysical Model Of the Monarch Sand Reservoir

Overview

Deriving the input parameters needed for fluid flow simulations requires that the 3-dimensional distribution of petrophysical properties be estimated throughout the simulation volume. To this end, a series of petrophysical models are developed for the Pru Fee and surrounding area using Heresim^{TM}, a proprietary code that combines integrated geostatistical modeling and reservoir upscaling capabilities. Geophysical logs from 36 wells, combined with detailed core-derived information from corehole Pru 101, provide the foundation needed to estimate the spatial distribution of facies type, permeability, and porosity. Although a much larger number of wells exist in the vicinity of the Pru Fee, the geophysical log suites needed to estimate permeability and porosity are available only for 36 wells.

Developed by the Institute Francais Du Petrole (IFP) and collaborators (ARMINES and BEICIP-FRANLAB), Heresim^{TM} is distributed in the United States by Geomath. The code is specifically designed to foster the collaboration of sedimentologists, geostatisticians, reservoir geologists and reservoir engineers in building integrated reservoir models. Several features of the code reflect the obvious desire of the programmers to allow subjective geological inference to be combined with geostatistical modeling. For example, vertical proportion curves and variograms provide a graphical synthesis of the distribution of sedimentary units that can be used, in turn, to design petrophysical models that provide a best fit to the geological environment. The following sections outline how the code is being applied in our study of the Pru Fee.

Defining Model Boundaries and Major Lithotypes

The petrophysical models are computed within a domain that surrounds the reservoir simulation volume and contains data derived from wells drilled in adjacent leases. The upper boundary of the modeling domain, and reservoir top, is the top of the Monarch Formation. An contour map of this surface was computed with Heresim™ using log picks from the 36 wells. The bottom of the modeling domain is less easily defined because many wells terminate before penetrating the oil-water contact. Yet, the high permeability of the Monarch Formation below the oil-water contact requires that we include a portion of the aquifer that underlies the oil-saturated zone in the reservoir simulations. As a first approximation, the geometry of surface S3 is assumed to provide a reasonable geometry for the bottom boundary of the petrophysical model. Thus, the bottom boundary of the petrophysical model parallels surface S3 at a depth of 61 m [200 feet] below S3.

During geological analysis of the reservoir data it became apparent that S3 forms an important surface separating two major lithotypes. Thus, separate petrophysical models are computed for the Upper and Lower lithotypes. Probability distribution functions that reflect the character of permeability and porosity within each lithotype are estimated using univariate statistics derived from corehole Pru 101. Spatial variability in facies type, characterized using both variograms and vertical proportion curves, provides a basis for estimating the spatial distribution of permeability and porosity. Before the characteristics of each lithotype can be analyzed, however, the modeling grid must be defined.

Model Gridding

Petrophysical models are computed using a 3-dimensional gridded volume with $\Delta x = \Delta y = 9m$ [27 feet]. Two vertical gridding approaches are used; proportional gridding in the Upper lithotype and parallel gridding in the Lower lithotype. The proportional gridding used in the Upper lithotype distributes a set of non-horizontal computational layers (in this case 100) evenly spaced between the top of Monarch and surface S3. Thus, the layer thicknesses vary as a function of the vertical distance between the bounding surfaces. The parallel gridding used in the Lower lithotype creates a set of non-horizontal computational layers with each layer parallel to surface S3. Because the bottom boundary of the model parallels surface S3 this yields a set of 120 computational layers with the same, constant thickness of 0.5 m [1.6 feet] throughout the model domain. Using this approach a total of 220 computational layers are defined that extend laterally throughout the model domain.

Computing Facies Type

Heresim^{TM} uses an indicator approach to develop a petrophysical model. First, facies distributions are interpolated throughout the 3-dimensional modeling domain. Second, permeability and porosity are assigned to individual gridblocks within each facies type using a probabilistic method. Using the indicator approach requires that facies distributions be defined using geophysical log suites collected at each of the 36 wells shown in and augmented with core data from wells Kendon 405, Pru 533, and Pru101.

The criteria used to estimate facies type from the geophysical log suites (Table 3.1) involve a two step process. First, a combination of resistivity and density thresholds are used to distinguish muddy Facies 4 sediments from the sandier Facies 1, 2, and 3. Second, computed porosity is used to discriminate between the three sandy (non-muddy) facies.

- Step 1 - Separate muddy sediments from sandy sediments

  Criteria: Facies 4 - muddy sediments = Resistivity 15 m and Density 2.1 g/cm^3

- Step 2 - Discriminate between the three sandy facies

Criteria:	Facies 3 - medium sand	= Porosity > 32%
	Facies 2 - coarse/granule sand	= 25% Porosity >= 32%
	Facies 1 - pebbley sand	= Porosity < 25%

The distribution of facies types identified in Pru 101 using these log-based criteria compare favorably with the facies types observed in the Pru 101 drillcore.

Because the geophysical data for each well are tabulated on 0.15 m [0.5 foot] increments, computed facies type is assigned at each well location on a 0.15 m [0.5 foot] spacing. Where core data are used to identify facies type (wells Kendon 405, Pru 533, and Pru 101), the 0.3 m [1 foot] spacing of the core plugs yields facies type assignments at a 0.3 m [1.0 foot] spacing. Facies types are assigned in lost core intervals of Kendon 405, Pru 533, and Pru 101 using the corresponding log-derived data at a 0.3 m [1 foot] spacing.

Once facies types are identified within each well, this information is transferred to the corresponding gridblocks that represent the computational layers intersected by the wells. Because a relatively fine vertical grid is used, little lumping or averaging is required. Thus, assigning facies to the vertical series of gridblocks associated with each well is straightforward. The vertically gridded well data provide a foundation for computing the facies-based variograms and vertical proportion curves used by Heresim™ to interpolate facies distributions throughout the model domain.

Variography

Both experimental variograms and fitted variogram models used to characterize the spatial distribution of facies type were created for each lithotype. The relatively large number of wells provides horizontal variograms with sufficient character for reasonable model fitting. Testing for horizontal variogram anisotropy reveals that the data are best approximated using omnidirectional variograms. The high-density of vertically distributed data (0.15 m [0.5 foot] spacing for geophysically-derived data and 0.3 m [1 foot] spacing for core-derived data) provides extremely well-defined vertical variograms. Although the variograms obtained for each lithotype are similar, greater horizontal and vertical correlation lengths are found in the Upper lithotype (Table 3.1). This result is consistent with the geological interpretation that the Upper lithotype comprises a sequence of distinctly thicker depositional units that are likely to be more continuous in lateral extent. Note that the horizontal range of 200 to 300 m [660 to 980 feet] provides a correlation length for each facies type that is greater than the lateral dimensions of the Phase I reservoir simulation volume (54 m by 54 m [180 by 180 feet]).

Table 3.1: Summary of Variography Results*

Lithotype:	Horizontal Range		Vertical Range	
	(m)	(feet)	(m)	(feet)
Upper	300	980	10	33
Lower	200	660	5	16

* NOTE: One model is concurrently fitted to all 4 facies types within each lithotype.

In order to provide a straightforward work flow the developers of Heresim™ restricted the variogram modeling capability to allow only an exponential variogram model. In addition, each group of facies types found within a specific lithotype is fitted with a single variogram model. Thus, the same range is assigned to the horizontal or vertical variogram model associated with all 4 facies found within each lithotype (Table 3.1).

Vertical Proportion Curves

A vertical proportion curve is a stacked bar diagram that represents the vertical distribution of the percentages of all the facies found within a specific lithotype. The curve is developed on a layer by layer basis by computing the areal percentage of each facies type found within a specific layer and plotting the result as a stacked histogram. Vertical proportion curves provide a valuable tool for summarizing and quantifying geological information contained in the facies descriptions. In addition, because the proportion curves are used to condition the final geostatistical simulations, manual modification of the curves enables important details of the sedimentary geology to be accounted for in the modeling process. In this study, however, we simply use the unadjusted curves. The curves show that Facies 3 (coarse/granule sand) dominates both lithotypes with muddy Facies comprising only a small proportion of the reservoir.

Univariate Statistics

Univariate statistics are computed using values of porosity and permeability derived from core plugs collected in Pru 101. Because this well is located in the middle of the region of interest, these data form an important basis for computing and conditioning the petrophysical models. The statistics obtained for Facies 1 (pebbley sand), 2 (coarse/granule sand), and 3 (medium sand) are summarized in Table 3.2. Insufficent data are available to evaluate the character of muddy Facies 4.

Table 3.2: Univariate Statistics for Porosity and Permeability from P 101

	Facies 1 Pebbley		**Facies 2** Coarse/Granule		**Facies 3** Medium	
	Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)
Min.	24.9	748	26.2	770	28.6	185
Max.	32.9	4134	36.2	6000	43.6	5268
Mean	28.6	2277	31.1	3301	33.5	2004
Std. Dev.	2.2	1039	1.8	2702	2.6	1154
No. Points	21	21	120	120	66	66

Several features of the statistics summarized in Table 3.2 are of interest. First, mean porosities increase from 28.6% to 33.5% with decreasing grainsize (from pebbley to medium sand). Second, there is no corresponding trend in the permeability values which are consistently very high in these sandy facies (about 200 to 6000 mD). Third, the permeability distributions are better approximated as normal, rather than log-normal, distributions. A subsequent section outlines how these data are used directly in developing the petrophysical models.

Geostatistical Simulations and Assignment of Petrophysical Properties

The variogram models and vertical proportion curves described in the previous sections provide the input needed for Heresim^{TM} to compute a series of realizations for the 3-dimensional facies structure. This process involves using a Gaussian simulation approach to compute facies indicator functions. Each facies indicator function forms a particlar realization of a random set of facies assignments. Each realization is one of a series of equiprobable realizations. Each new realization is generated by varying only the numerical seed used in the geostatistical simulations. The simulation results are explicitly conditioned by the well data and constrained to produce vertical proportion curves that resemble the ones computed using the well data.

Table 3.3: Permeability and Porosity Distributions Assigned to Each Facies

Porosity (%)

Facies	Min	Max	Mean	Std. Devn
4 - muddy	32.0	38.0	35.0	1.0
3 - medium sand	28.6	43.6	33.5	2.6
2 - coarse/granule sand	26.2	36.2	31.0	1.8
1 - pebbley sand	24.9	32.9	28.6	2.2

Permeability (mD)

Facies	Min	Max	Mean	Std. Devn
4 - muddy	10	200	35	10
3 - medium sand	185	5267	2004	1154
2 - coarse/granule sand	770	6000	3300	2702
1 - pebbley sand	748	4133	2277	1038

Values of permeability and porosity associated with each facies type are assigned to each gridblock using a probabilistic approach. The univariate statistics computed from the core plug data of Pru 101 provide the probability distribution functions (pdfs) for Facies 1, 2, and 3. The pdf for Facies 4 is estimated based on the experience of the project team. The pdfs used in this study are summarized in Table 3.3. Heresim^{TM} uses a randomized approach to select values of permeability and porosity from the pdf associated with the facies type assigned to a particular gridblock. In all cases, permeability tensors are assumed to be isotropic thus $k_x = k_y = k_z$. A small number of permeability tests performed on oriented plugs cut from the Pru 101 core suggest that permeability anisotropy is negligible.

Difficulties in visualizing the fine scale distribution of permeability and porosity in black and white preclude presenting detailed petrophysical distributions in this document. Suffice to say, however, the high degree of overlap in petrophysical properties estimated for Facies 1, 2, and 3 yield a reasonably homogeneous distribution of permeability and porosity. The upscaling procedure is described in the next section.

Upscaling

Upscaling is required to assign representative values of permeability and porosity within the 6 by 6 reservoir simulation model domain. In this study, we need only upscale in the vertical direction because the reservoir simulation grid matches the 9 m by 9 m petrophysical simulation grid. In constructing a computationaly affordable model we elected to reduce the 220 layer petrophysical grid to a 20 layer reservoir simulation grid. A simple arithmetic averaging method is used to upscale porosity. Permeability is vertically averaged using a three-step algebraic method. First, the maximum averaged permeability is computed by finding the harmonic mean permeability of the blocks to be vertically upscaled. Second, the minimum averaged permeability is computed by finding the arithmetic mean of the same gridblocks. Finally, the harmonic mean of the computed maximum and minimum values is assigned as the upscaled permeability in the reservoir gridblock. Note that the 6 by 6 model grid is later refined by transforming each horizontal gridblock into 4 gridblocks. This allows us to preserve the computed petrophysical model while adding the additional nodes needed to ensure that the final computational mesh will produce reasonable values of computed pressure, temperature, and oil saturation.

The final reservoir model is constructed by cutting out a 6 by 6 by 20 gridblock domain and exporting the gridded values of permeability, porosity, gridblock thickness, and gridblock center location to the reservoir simulator. The high degree of overlap in permeability and porosity found in the group of sandy facies types (Facies 1, 2, and 3) yields a relatively homogeneous set of parameter distributions.

The overall character of the permeability and porosity values associated with the upscaled results of 8 realizations is summarized in the univariate statistics of Table 3.4. Although two realizations (#4 and #7) have minimum values of permeability that lie well below those of the other realizations, the overall statistics associated with the permeability and porosity models differ little from realization to realization. As a first step in attempting to compute net oil in place the total pore volume and bulk average porosity found within both the final 6 by 6 reservoir model and the reservoir volume corresponding to the Pru Fee are calculated for Realization #1. Computed pore volumes are 3,599,809 m^3 for the Pru Fee and 81,617 m^3 within the 6 by 6 reservoir model. Bulk average porosities are approximately 31.3% for both the Pru Fee and the reservoir model volumes. This value is similar to those computed for each of the 8 realizations of the reservoir model (Table 3.4).

Table 3.4: Summary of Univariate Statistics for Permeability and Porosity Assigned in Eight Upscaled Reservoir Models

Porosity (%)							
Realization	Means			Std.Dev.	Coeff.	Max	Min
	Arith.	Geom.	Harmon.		of Varn.		
1	31.4	31.3	31.3	1.16	0.037	35.6	27.9
2	31.5	31.5	31.4	1.17	0.037	36.1	27.7
3	31.3	31.3	31.3	1.14	0.036	35.5	27.7
4	31.6	31.6	31.6	1.21	0.038	36.9	27.5
5	31.3	31.3	31.3	1.10	0.035	35.8	27.5
6	31.4	31.3	31.3	1.17	0.037	36.3	27.7
7	31.1	31.0	31.0	1.43	0.046	36.2	26.2
8	31.3	31.3	31.2	1.26	0.040	36.4	27.1

Permeability (mD)							
Realization	Means			Std.Dev.	Coeff.	Max	Min
	Arith.	Geom.	Harmon.		of Varn.		
1	3234	3139	3007	714	0.221	5577	574
2	3120	3036	2922	673	0.216	5450	327
3	3167	3057	2903	752	0.247	5565	570
4	3097	2884	1725	790	0.255	5259	29
5	3258	3182	3095	667	0.205	5368	1066
6	3186	3096	2983	707	0.222	5552	685
7	3002	2835	2121	779	0.259	5253	31
8	3172	3082	2940	686	0.216	5660	275

Summary

The Heresim™ code provides a straightforward environment for constructing geologically plausible realizations of the permeability and porosity structure at the Pru Fee. A fine-scale geostatistical model of four facies types is developed using an indicator approach constrained by geophysical logs from 36 wells and core data from 3 wells. Permeability and porosity are assigned within each facies type using probability distribution functions derived from core data collected in a recently drilled well located in the middle of the model domain. Even prior to upscaling the petrophysical model it is clear that relatively homogeneous models are constructed for each of eight realizations. The upscaled 20 layer models form the basis for fluid flow simulations used to evaluate the production potential of the Pru Fee.

Chapter 4

Steam Flood – Review of Alternative Technologies

General statement

For the identification of possible applicable technologies, a literature search was completed using the Society of Petroleum Engineers (SPE) Image Library. This technical literature database, on CD- ROM, includes all SPE published papers from the 1950's through 1995. The search included all publications related to recovery of heavy oil using both thermal and non-thermal techniques. Over one hundred papers which appeared to present potentially applicable technologies were reviewed. Of these, about fifty are of interest within the scope of the Pru DOE Class III project. A complete bibliography of these papers is included in this chapter for reference.

Summaries of the key information in the papers reviewed are grouped by technology type as follows. The technologies are related to practice in the Midway-Sunset field in general and on the Pru property in particular, as appropriate.

Steamflooding

Economic steamfloods have been performed in heavy oil reservoirs as thin as only 15 feet. Since the reservoir thickness averages at about 275 feet at Pru, this will not be a limitation. Chevron claims to have had some success in the West Coalinga field using the *Water Alternating Steam Process*. This process works by alternating slugs of steam and water over repeated cycles. Chevron claims this process worked by partially collapsing the steam chest, and reducing steam channeling.

Optimum steamflood pattern configuration for a trough reservoir places the injector away from the synclinal axis, a row of producers updip from the injector, and another row of producers near the synclinal axis. The maximum production is obtained by starting the steamflood with an intermediate steam rate (2 bbl per day per acre-foot) and high steam quality (50% or greater), and termination of the steamflood after 5.5 years. These numbers were used to guide technology implementation at Pru. According to Kumar, for confined patterns, a reduction in injection rate after steam breakthrough is beneficial. A linear reduction schedule resulted in the highest discounted net oil production with a lower *Steam/Oil Ratio* (SOR) than a constant injection schedule. Ziegler states that for constant values of well spacing and injection rates, oil recovery from an inverted nine spot pattern was accelerated relative to the five spot pattern. Reservoir simulation sensitivity studies were used to study these aspects at Pru. If initial injectivities were low, high-rate pulsed injection has been used to create extensive horizontal fractures to improve areal thermal conformance in a steamflood (implemented in Cold Lake).

Several types of foam and gel agents appear to be successful in diverting injected steam, thereby increasing the volumetric efficiency of the steamflood and improving the utilization of the heat injected into the reservoir. Since considerable diversion (to the top) is observed at Pru, some of these methods might be applicable at Pru.

Cyclic Steaming

While the lower rates of heat delivered by cyclic steaming may provide a more efficient utilization of injected steam as compared to rapid heating rate of a steamflood on an equivalent cumulative pore volume basis, much lower net cash flows may result in poorer relative economics. Cyclic steaming also is inefficient with low initial reservoir energy (as is the case in Pru). Sequential cyclic steaming is recommended for thick steeply-dipping reservoirs. Performance of cyclic steaming at Pru is compared to the those of flooding processes later in the report.

Non-Steam Enhanced Recovery

Cold production of heavy oil has been successfully applied in thin reservoirs (15-45') in Canada. This method requires production and handling of large volumes of sand. CO_2 flooding required very high pressures to enhance heavy oil recovery in core studies. CO_2 has been tried also with steamflooding, accelerating some production' but resulting in no incremental recovery. Experiments using carbon dioxide and methane as additives to steam injection proved that the ability of the gases to reduce heavy oil viscosity diminishes rapidly with increased temperature. Microbial enhanced oil recovery is feasible in low temperature reservoirs. *In situ* combustion has experienced severe operational problems due to the high temperature experienced when the combustion front reaches the producers. Areal control and rate of advance of the front has proved to be difficult. Doscher concludes that fireflooding is not a significant method for recovering heavy oil. Electromagnetic magnetic heating has been used in horizontal producers in thin heavy oil reservoirs with bottom water. According to a study conducted by Farouq Ali, it can be concluded that most of the non-thermal recovery methods are only marginally effective.

Horizontal Wells

Incorporating horizontal wells at the start of a steamflood appears to be a feasible approach for alleviating steam override. The initial productivity can be higher than that of vertical wells, thereby helping to reduce the ultimate number of wells and possibly obviating the need to steam soak producers. Re-entry of vertical wells to drill new horizontal laterals has been successful in restoring productivity of old wells. Physical models have been used in the laboratory to show that a combination of horizontal steam injectors and vertical producers can be used to optimize steamflood performance. A project in Oman successfully drilled 78 horizontal producers to recover heavy oil from a 60 to 200 feet thick bottom-water reservoir. An additional 300 horizontal producers are planned. Horizontal producers were successfully applied to an 85 feet thick heavy oil reservoir to reduce sand production. Multiple ultra-short radius horizontal laterals were successfully drilled in the Midway Sunset field vertical producer, significantly increasing production rates. Applicability of using horizontal wells at the project site will be explored later in the project.

Project Surveillance

Project surveilance is extremely valuable since project adjustments based on process understanding can steer the project toward economic success. Some of the effective surveilance tools are listed below. A high density *Temperature Observation Well* (TOW) program is an effective method for analyzing the thermal heating process within the reservoir. Geostatistical mapping of reservoir temperature from temperature logs can be easily applied and provide a more accurate picture than is otherwise available. FDC/CNL logs have been used in observation wells to calculate steam saturations in the reservoir. Radioactive tracers in steam injection, and water cut salinity analysis can be used to determine the areal conformance of an injection project. Strat-holes have been drilled by some operators at one tenth of the cost of a new producer to gather information on oil-water contact depth, desaturation zones, and reservoir heating. Cross-well tomography has been used to identify heated oil zones and heterogeneities in the Midway-Sunset field. Good database management can leverage the success of an enhanced oil recovery project. Computer surveillance programs, analytical models and simple numerical simulators are being used to optimize day to day operations. Optimal control theory can be used to determine optimal steamflood operating parameters. Statistical analysis can be used to manage project risk. Most of the above tools are being used in the Pru project.

Reservoirs With Bottom Water

Previous studies suggest that vertical permeability barriers improve recovery in most bottom water reservoirs and also that a horizontal well would overcome water coning problems. Others observed that producing wells farther away from the bottom water will perform better. Inert gas injection can be used to establish a flow path in a cold heavy oil reservoir prior to steamflooding in order to avoid losing heat to bottom water. Bottom water is by far the most serious problem at Pru. Lack of vertical barriers compounds this problem. Specific strategies to address this problem were devised in this project.

Well Completions

Chevron recommends the use of 6 5/8", 50 mesh, foamed in tight hole slotted liners for Monarch producers on their 26C lease, located adjacent to the Pru lease. They also concluded that steamflooding the Monarch sand increased oil production significantly over cyclic stimulation response. Chiou states that limited entry perforating may not ensure successful elimination of poor injection profiles in multisand completions under certain reservoir conditions. High pH steam causes severe formation damage in the form of pore plugging, which in turn causes a drastic reduction in permeability. Watkins suggests adding ammonium salts, such as ammonium nitrate, and ammonium chloride to generator feedwater to reduce effluent pH. Model studies show that for downdip producers in a reservoir which is less than 200 feet thick should be completed over 100 percent of the reservoir thickness. Concentric simultaneous waterflood and steamflood has been performed with water injected down the tubing and steam injected down the tubing/casing annulus. Waterflooding following a steamflood may result in incremental oil recovery.

Optimum well completions were determined to be the answer to the bottom water problems. As the project progresses, specific recommendations will be made.

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Chapter 5

Initiation of Steam Flood Demonstration

Introduction

In January 1997 the project entered its second and main phase with the purpose of demonstrating whether steamflood can be a more effective mode of production of the heavy, viscous oils from the Monarch Sand reservoir than the more conventional cyclic steaming. The objective is not just to produce the pilot site within the Pru Fee property south of Taft (Figure 1), but to test which production parameters optimize total oil recovery at economically acceptable rates of production and production costs.

Well Drilling and Completions

During the period January 19 through April 11, 18 new wells (Table 5.1) were drilled and completed at the 8 ac pilot near the center of the Pru property (Fig. 2). Together with Pru 101, which was drilled in 1995 during the evaluation phase of the project, and eight older wells renovated and put on cyclic production at the start of the project, these wells form a four-fold, nine-spot well pattern. The older wells are B-1, 533, B-3, 12, C-2, C-3, D-1 and D-2. Each injector is surrounded by 8 producers located at the corners and middle edges of a square. Four squares are joined to form a larger square approximately 600 ft by 700 ft, or about 8 ac in size. Along the north edge of the array, a producer is missing from the ideal array between wells 533 and 201. The need to accommodate existing wells into the array has resulted in a departure from an ideal Cartesian spacing of the wells. About half of the producers, those in the interior of the array, are in potential communication with two or more injectors. In addition to the 24 wells in the production array, there are four temperature observation wells, each positioned within 80-180 ft of an injector. One of the temperature observation wells, Pru TO-1, was drilled during the initial phase of the project to monitor cyclic steaming in Pru 101. The other three wells were drilled at the start of the demonstration phase.

The injector and temperature observation wells were drilled and completed in a similar fashion. A 6.5 in hole was directionally drilled to about 100 ft below the projected oil-water contact (OWC) and Schlumberger *Platform Express* run in the open hole. A 3.5 in casing was positioned from the surface to the base of the hole (TD), baffled at a depth 32 ft above TD, and cemented in place. The circulation and casing of the wells was done by Halliburton. The casing in the injectors was perforated (Table 5.2) at six locations about 10 ft apart. This 47 to 60 ft interval of perforations was positioned 131 to 202 ft above the OWC and 39 to 47 ft below the top of the Monarch sand.

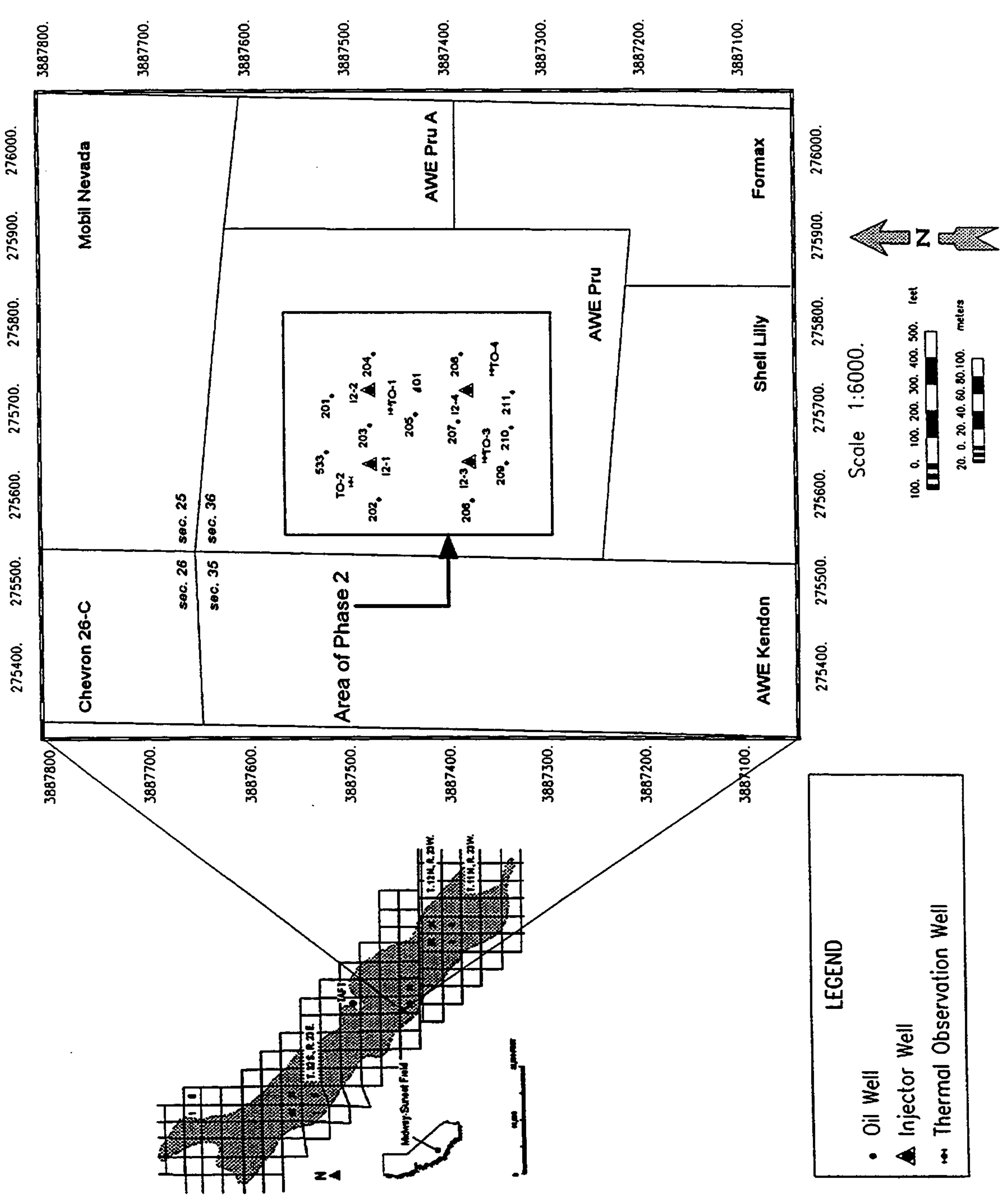


Figure 1. The Pru project encompasses the AWE Pru and adjacent leases. Wells used for the stratigraphic characterization in Phase 2 are within the AWE Pru lease. Map coordinates are in UTMs, zone 11.

Drilling and completion of the producers was more complicated. A 9 7/8 in hole was directionally drilled to a depth approximately 100 ft below the projected OWC. Schlumberger *Platform Express* was run in the open hole. A 7.0 in solid casing (23# J-55 LTC) was inserted to a depth about 25 ft below the top of the Monarch Sand, cemented in place and a 7 in wellhead installed. The float and cement at the base of the solid casing was drilled out and the remainder of the open hole through the Monarch Sand to TD was reamed out to a 13.0 in diameter. A 5.5 in liner was inserted inside of the casing to a depth 5 to 50 ft above TD and packed in place with 8 x 12 gravel. Gravel also fills the hole below the hole below the bottom of the liner to TD. The upper section of the liner above the base of the casing and the lower section from 30 ft above the OWC to the lower end is blank. A short segment near the base of the casing is semi-perforated. The remaining section of liner, the longer section through the Monarch Sand, is slotted. Within one or two weeks after release of the rig, tubing, rods and a pump were installed and the well run on production.

Each producer was primed by steaming before putting in full production mode. The target steam volume was 8,000 BS and the target rate 1,000 BSPD. However, the actual steam rates varied from 650 to 1,250 BSPD. Generally, the wells were soaked for 2 weeks after the steam jobs. The priming of the new producers began in March and was completed by the end of May, 1997.

The Schlumberger *Platform Express* runs include array induction, SP, temperature, density, neutron density, and gamma ray logs.

Production at the Pru Pilot

In Fall 1995, as the first phase of the project began, eight (8) old production wells were renovated and a new producer, Pru 101, was drilled. After an initial cycle of steaming in the period of October-December 1995, all nine wells were put on production (Fig. 3) as the cyclic baseline test. The eight old wells are those now included in the pilot array described above. Initial production, except from Pru 101 (Fig. 4), was generally poor. The wells were steamed again in February-May 1996, and yet again in July-August 1996. In general, rates improved during this period of repeated stimulation and continued production. During the cyclic test period, production averaged for the total group of nine wells about 70 BOD, ranging from 3 to 10 BOD/well for the old wells and about 15 BOD for Pru 101. The average production rate for the nine cyclic producers through the end of 1996 was about 8 BOD/well. The total production rate had begun to decline in the last months of 1996.

In the period January 11 through April 11, 1997 eleven (11) new producers were drilled. Each was primed by steaming in turn during March-May and immediately put into production. The result was nearly an order of magnitude increase in production rate from 50-60 BOD to nearly 400 BOD (Fig. 3). The sharp increase in production can, in part, be attributed to the increase in the number of producers from nine to twenty and the fact that the performance of the new wells is consistently better than the old renovated wells (Figs. 5 and 6. However, the well average jumped from about 8 BOD to nearly 20 BOD with the onset of the pilot steam flood. It anticipated that the performance will continue to improve as the steam chest builds within the demonstration site.

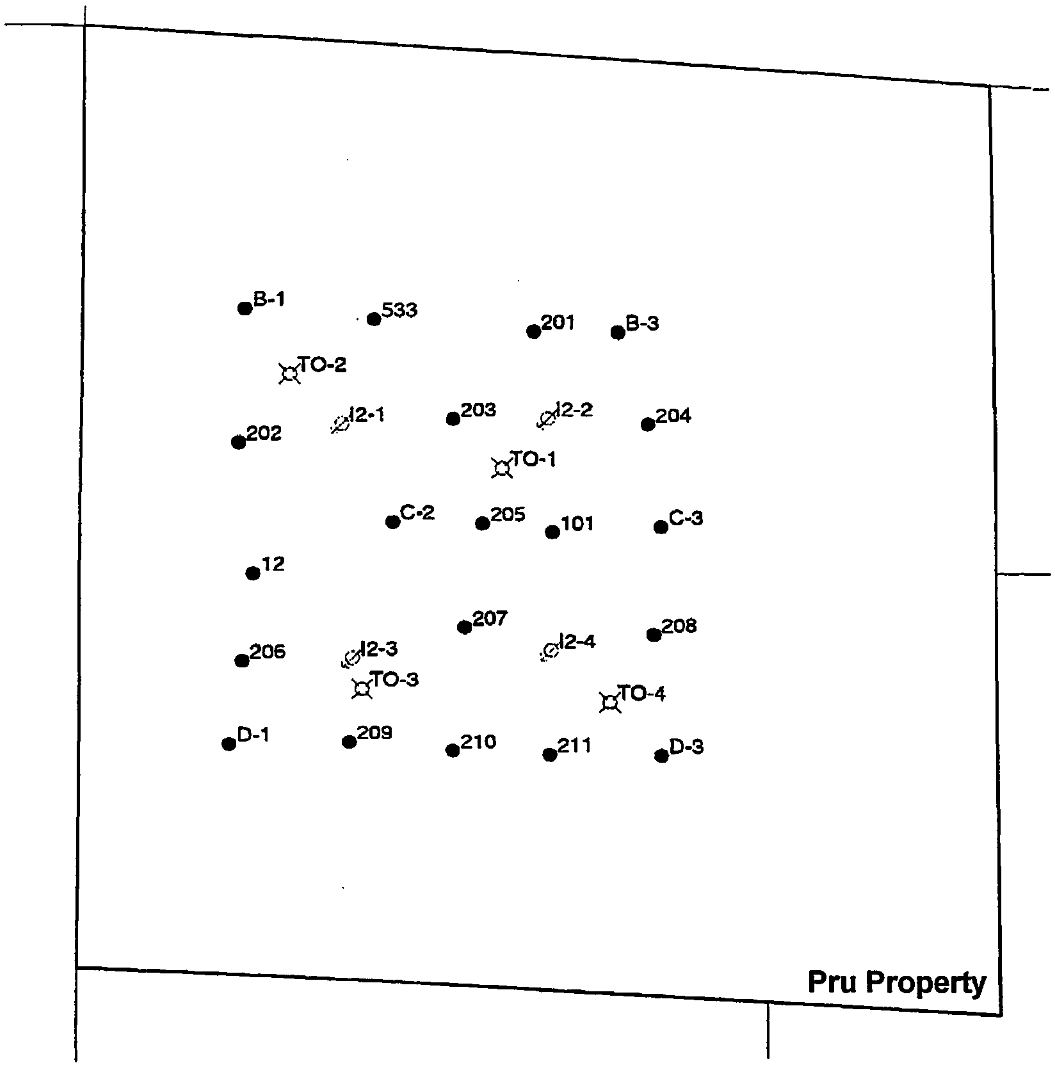


Figure 5.2: Production array for the 8 ac pilot steamflood demonstration on the Pru property. The Pru property is a total of 40 ac in size. The array of wells occupies a space approximately 160 ft by 170 ft.

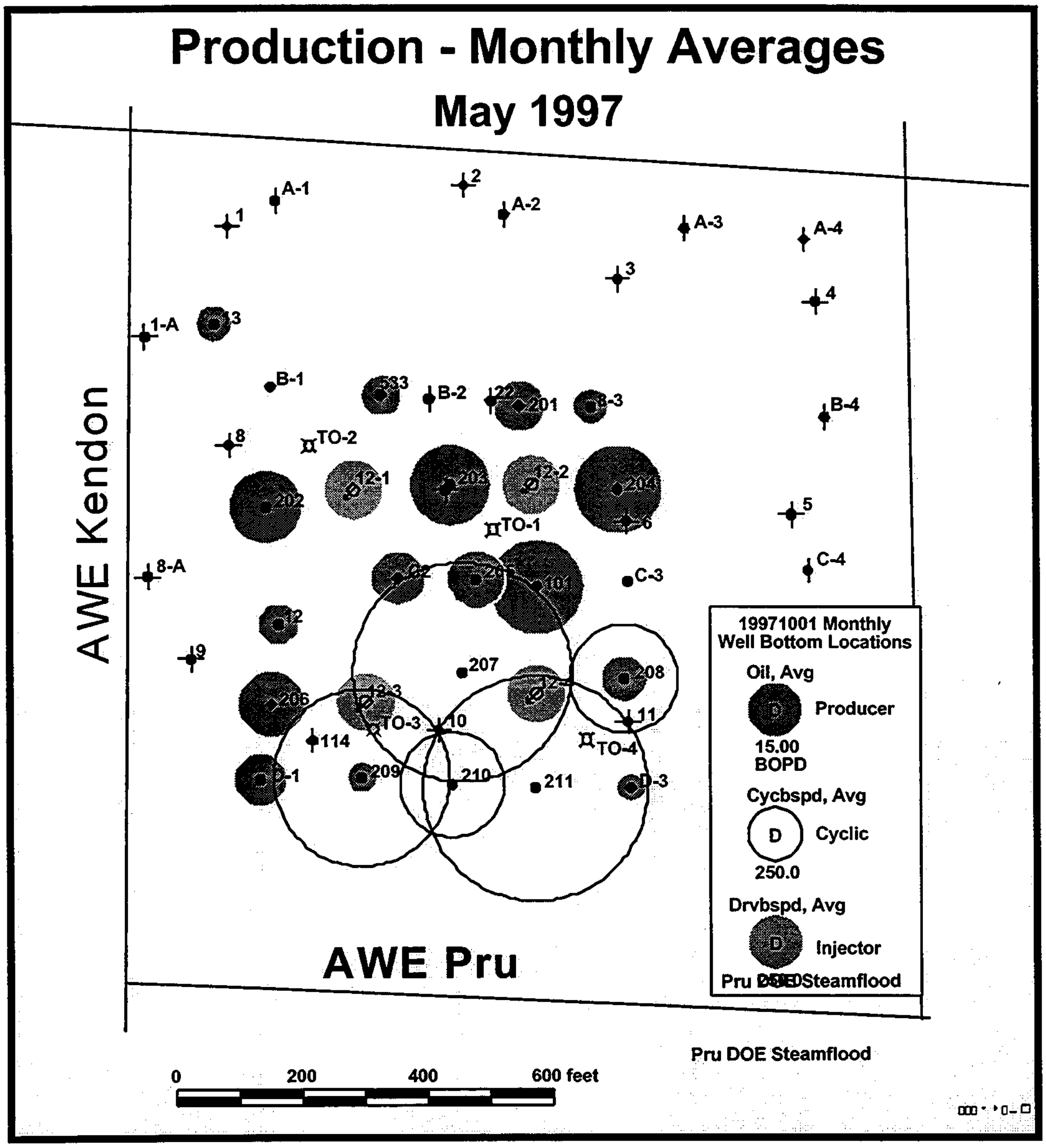


Figure 5.3: Production and injection at the Pru pilot in May 1997.

Table 5.1

MIDWAY-SUNSET FIELD CLASS III OIL TECHNOLOGY DEMONSTRATION PROJECT

ARCO Western Energy Pru Property: Section 36 Township 32S Range 23 E

Wells Drilled for the 8 ac Pilot Demonstration in Center of Property

Well Name	API Serial No.	Spud Date	Prod. Date	TD (ft)	KB (ft)	GL (ft)
Pru 101	04030-04475	9/16/95	10/11/95	1402	1394	1381
Pru 201	04030-07115	1/19/97	2/13/97	1512	1429	1416
Pru 202	04030-07114	1/27/97	4/11/97	1500	1383	1370
Pru 203	04030-07113	2/9/97	2/25/97	1497	1418	1405
Pru 204	04030-07112	2/6/97	2/15/97	1476	1393	1380
Pru 205	04030-07111	2/13/97	3/7/97	1468	1383	1370
Pru 206	04030-07110	2/20/97	3/28/97	1483	1399	1386
Pru 207	04030-07109	3/13/97	3/30/97	1452	1371	1358
Pru 208	04030-07108	2/9/97	3/4/97	1462	1372	1359
Pru 209	04030-07107	2/25/97	3/24/97	1482	1398	1385
Pru210	04030-07106	3/8/97	3/30/97	1400	1380	1367
Pru 211	04030-07105	3/1/97	3/23/97	1415	1355	1342
Pru I 2-1	04030-07151	2/17/97	NA	1471	1383	1370
Pru I 2-2	04030-07152	1/24/97	NA	1486	1393	1380
Pru I 2-3	04030-07153	3/11/97	NA	1464	1381	1368
Pru I 2-4	04030-07154	3/6/97	NA	1441	1359	1346
Pru TO-1	04030-04476	9/14/95	NA	1529	1394	1381
Pru TO-2	04030-07155	1/17/97	NA	1529	1445	1432
Pru TO-3	04030-07156	2/22/97	NA	1485	1398	1385
Pru TO-4	04030-07157	3/4/97	NA	1434	1355	1342

Table 5.2

Depths of Perforations in Injector Wells in the Pilot Demonstrtation

Well Name	Top Monarch	Perforations (ft)						OWC (ft)
Pru I2-1	1057	1104	1116	1123	1134	1142	1160	1362
Pru I2-2	1088	1127	1136	1142	1150	1160	1174	1361
Pru I2-3	1102	1149	1164	1177	1183	1200	1209	1367
Pru I2-4	1106	1150	1163	1178	1185	1198	1206	1337

Note: All well depths are in feet down hole, not TVD.

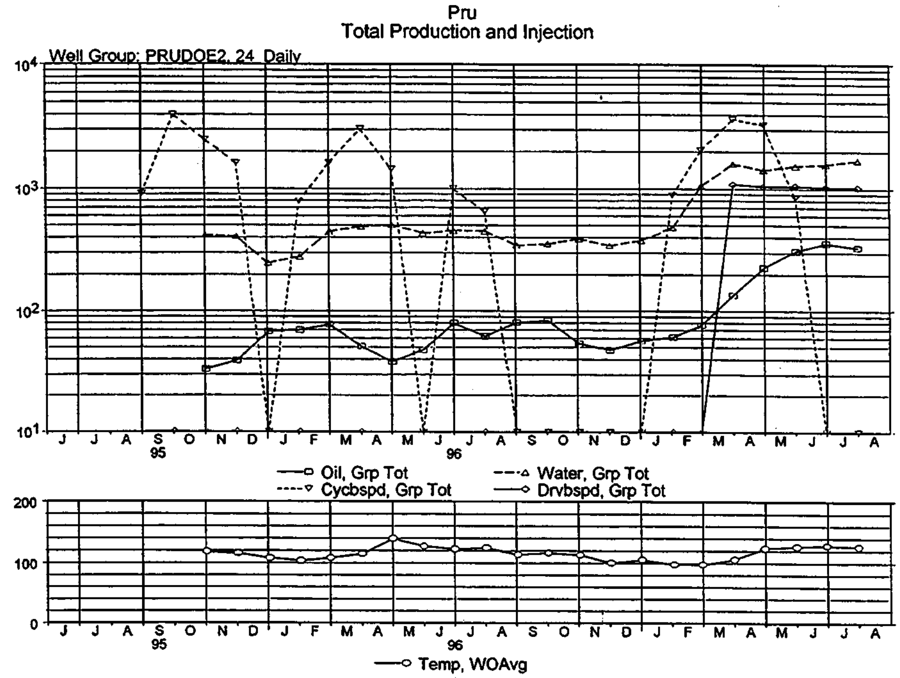


Figure 5.4: Total production from the Pru demonstration site through summer 1997

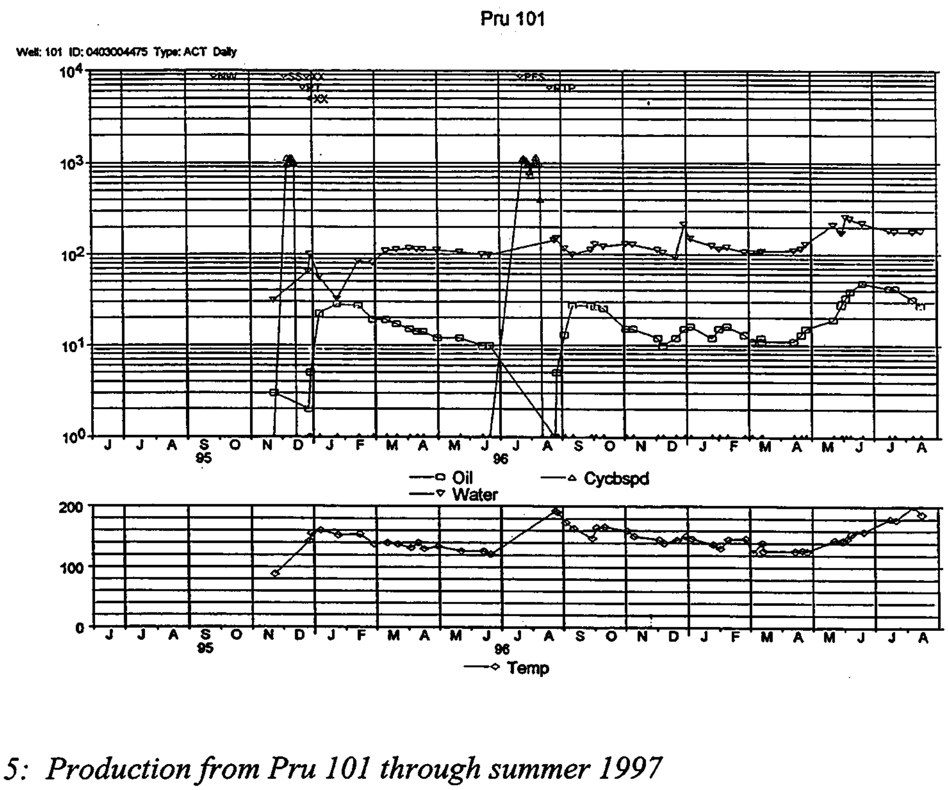


Figure 5.5: Production from Pru 101 through summer 1997

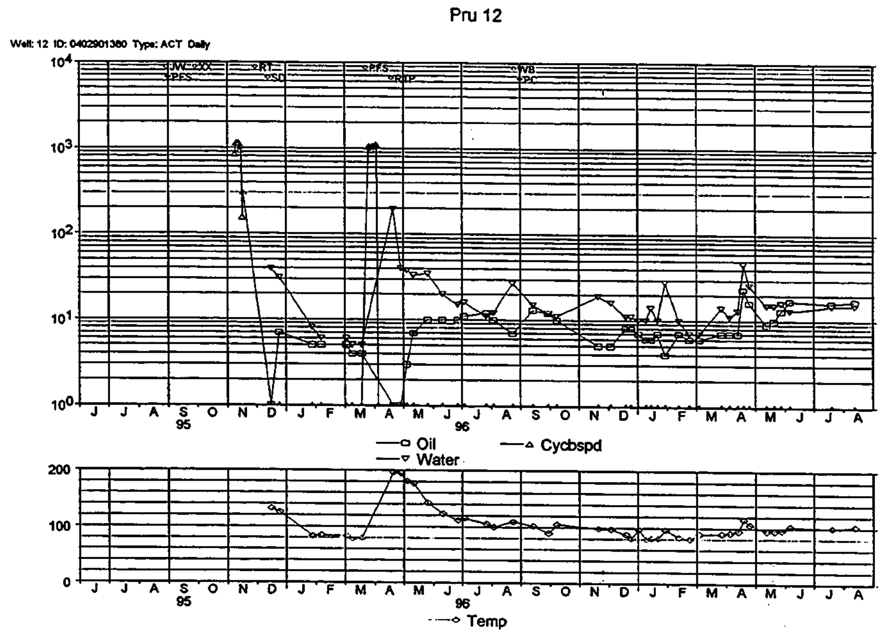


Figure 5.6: Production from Pru 12, an old well, through summer 1997.

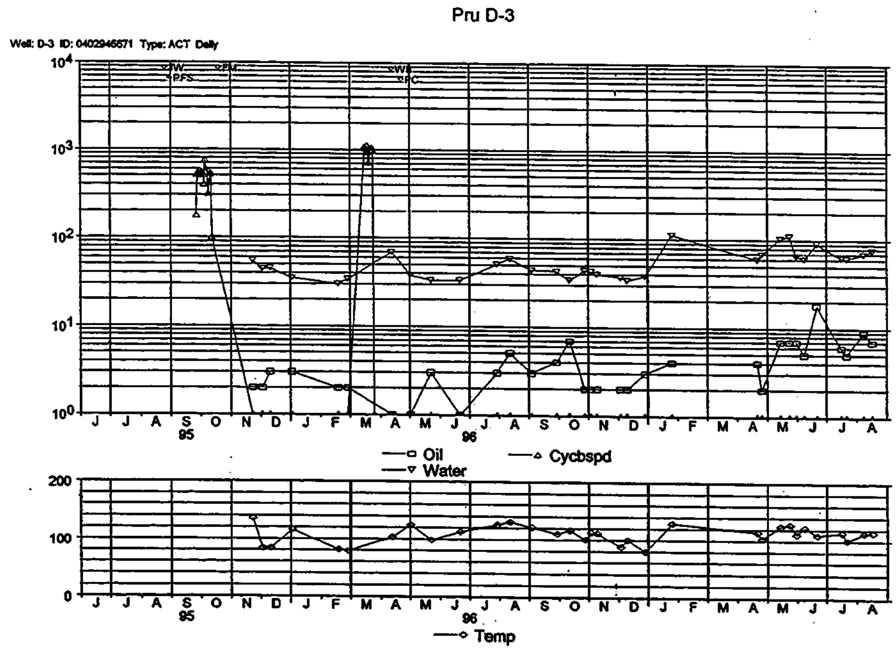
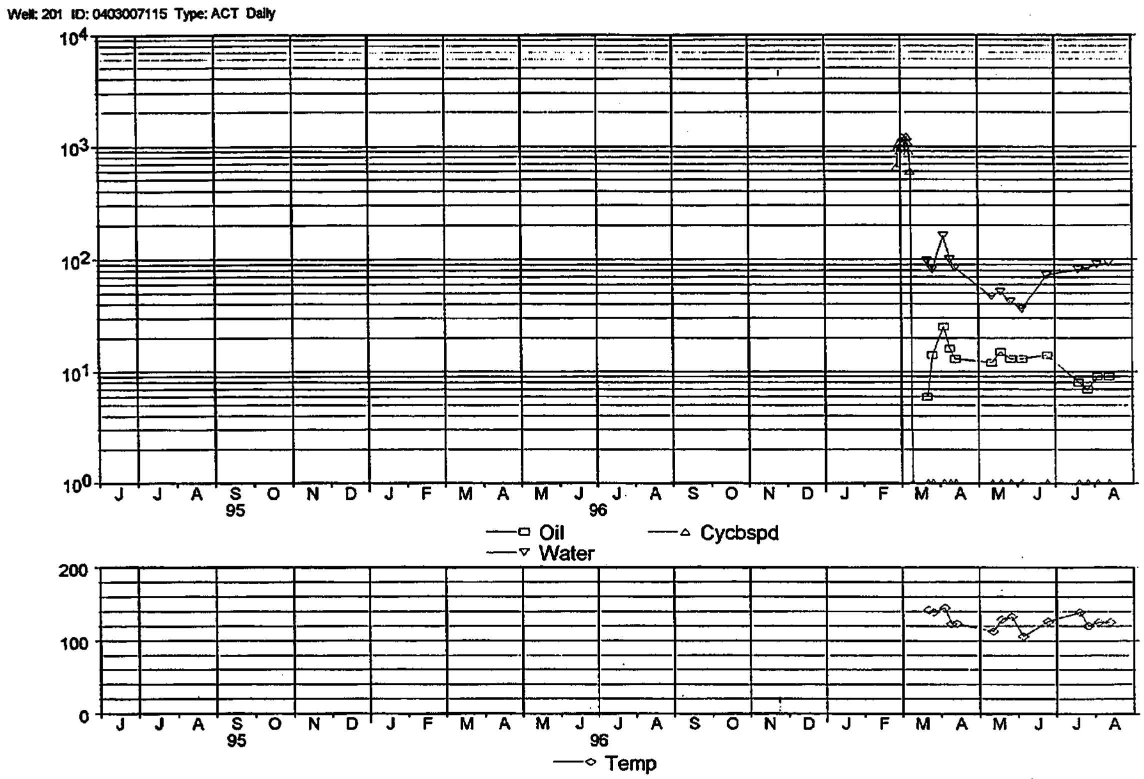
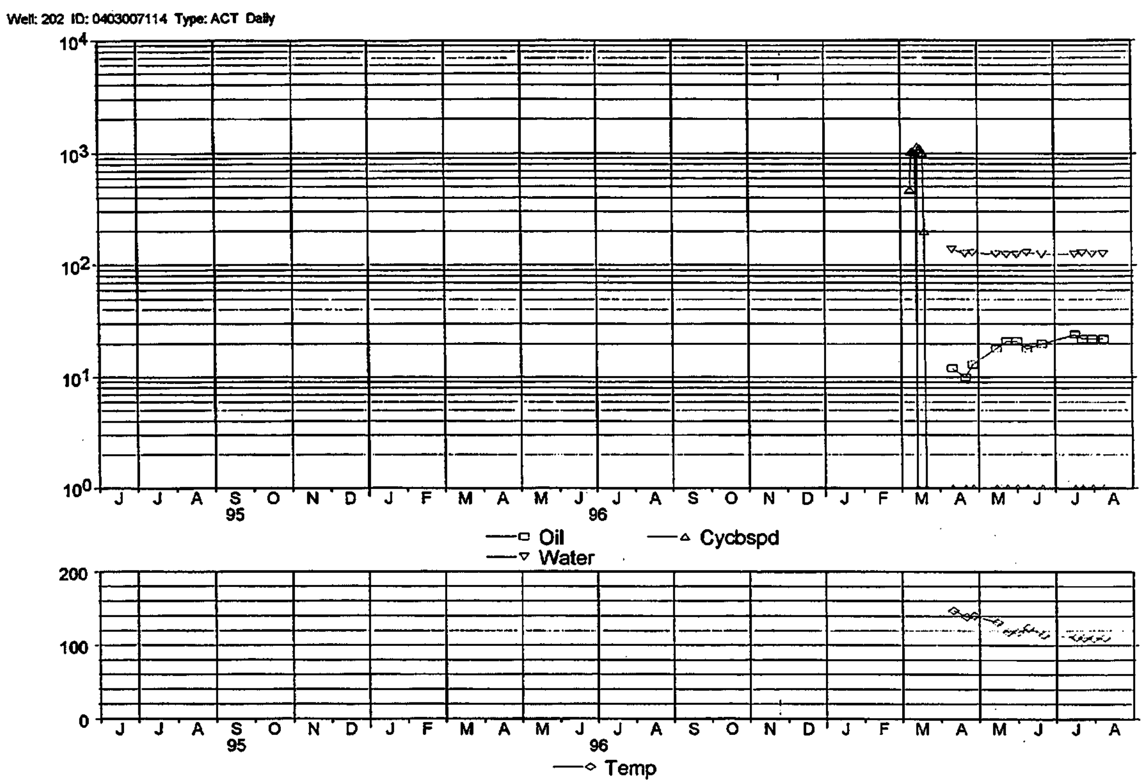


Figure 5.7: Production from Pru D-3, an old well, through summer 1997.

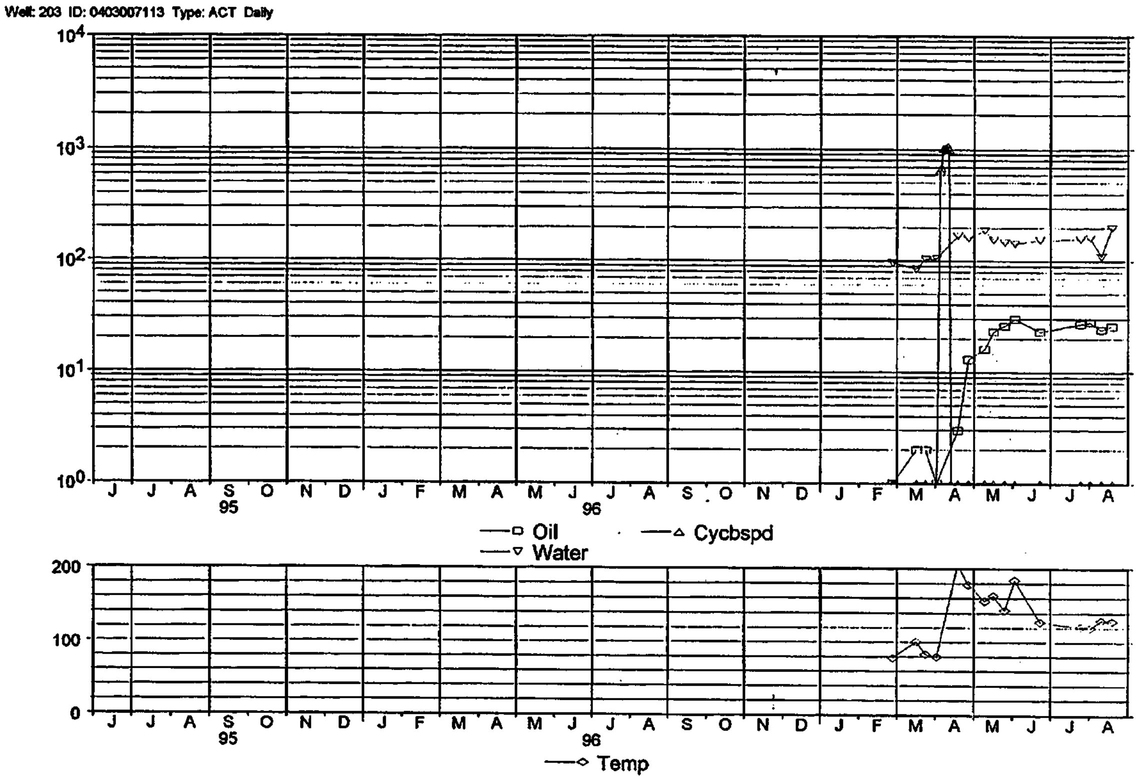
Pru 201



Pru 202



Pru 203



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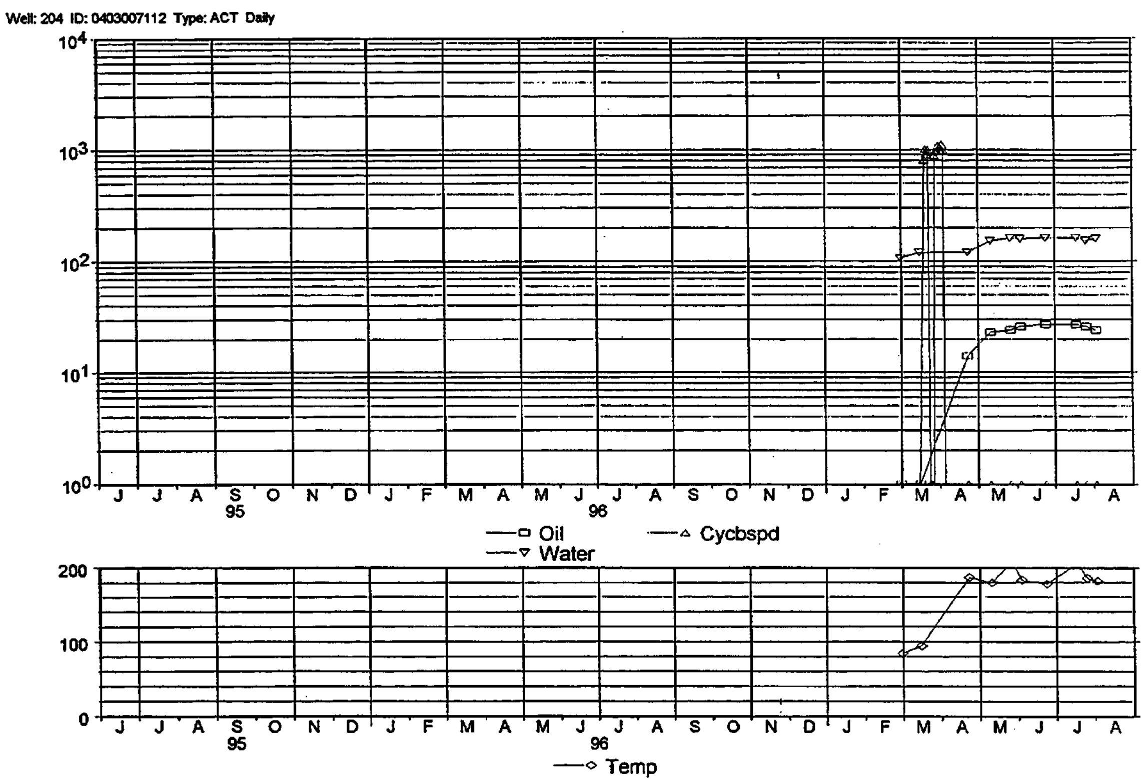
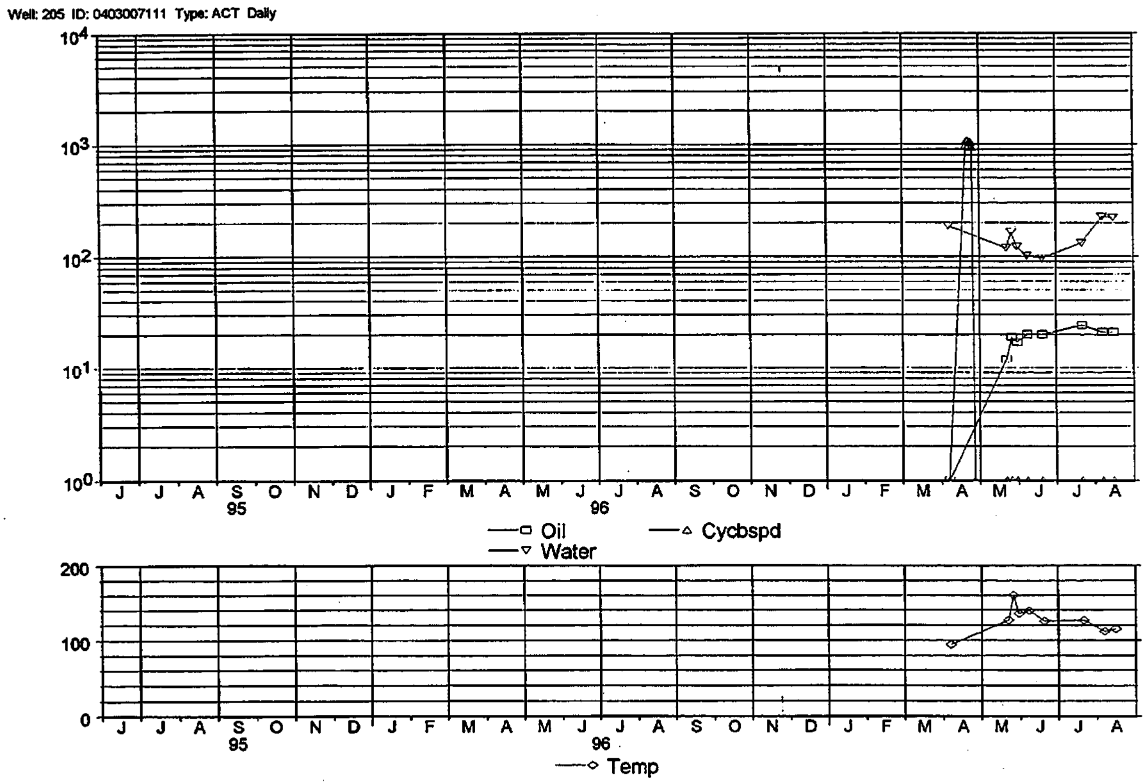


Pru 205



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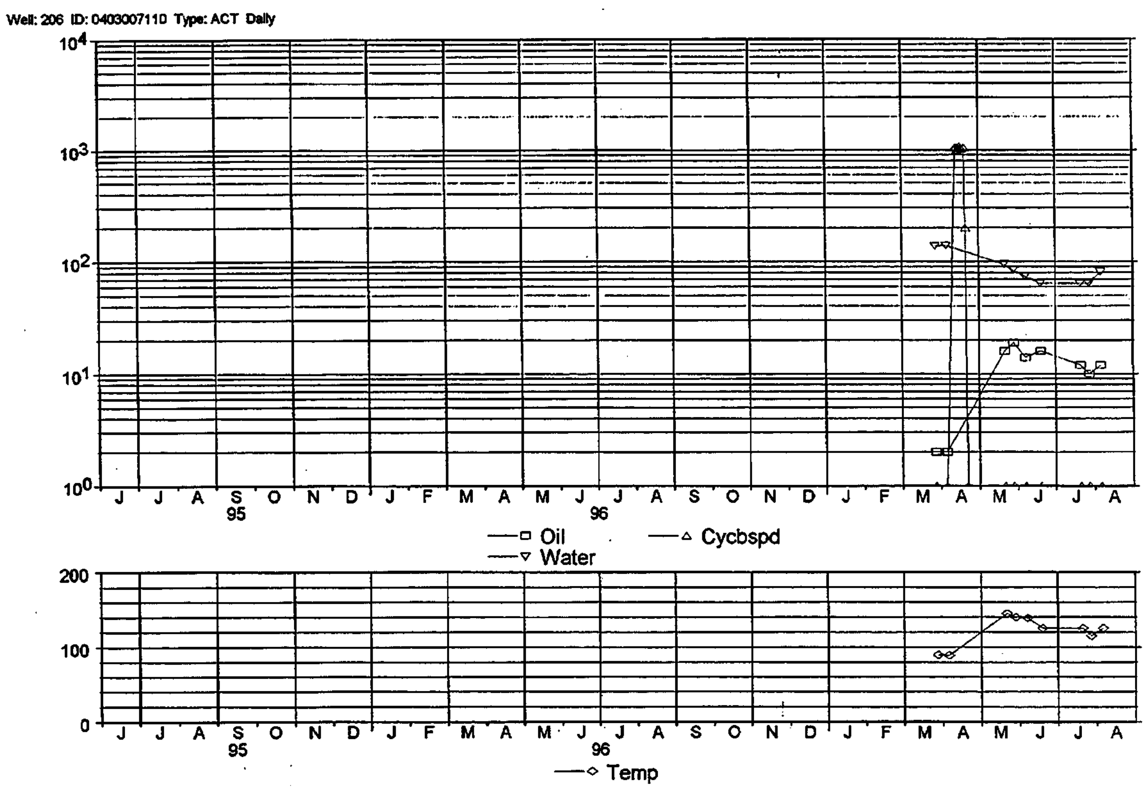

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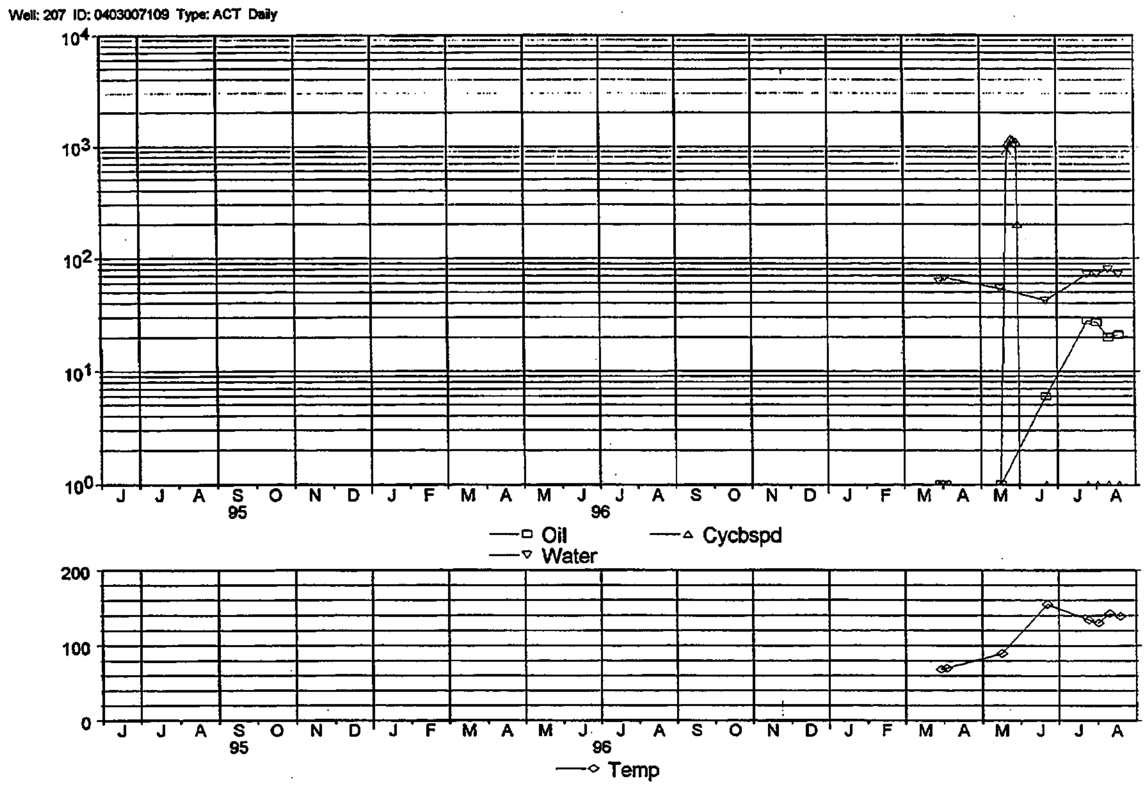
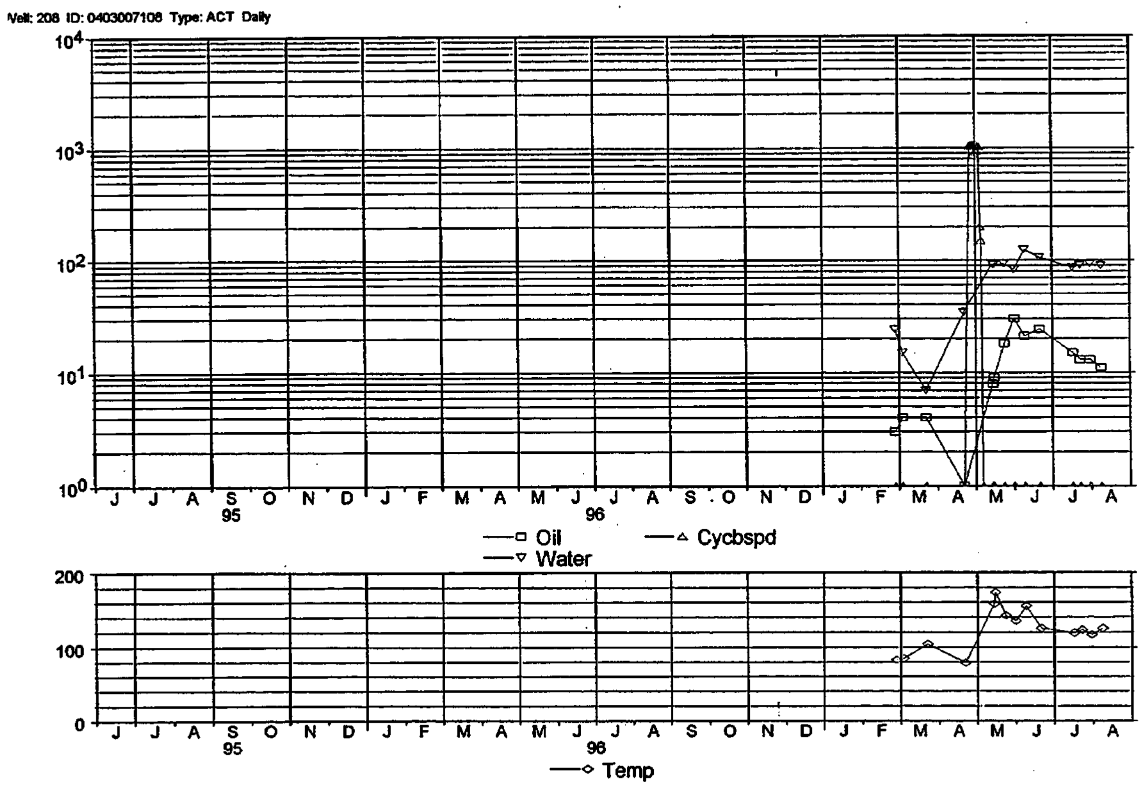


Pru 208



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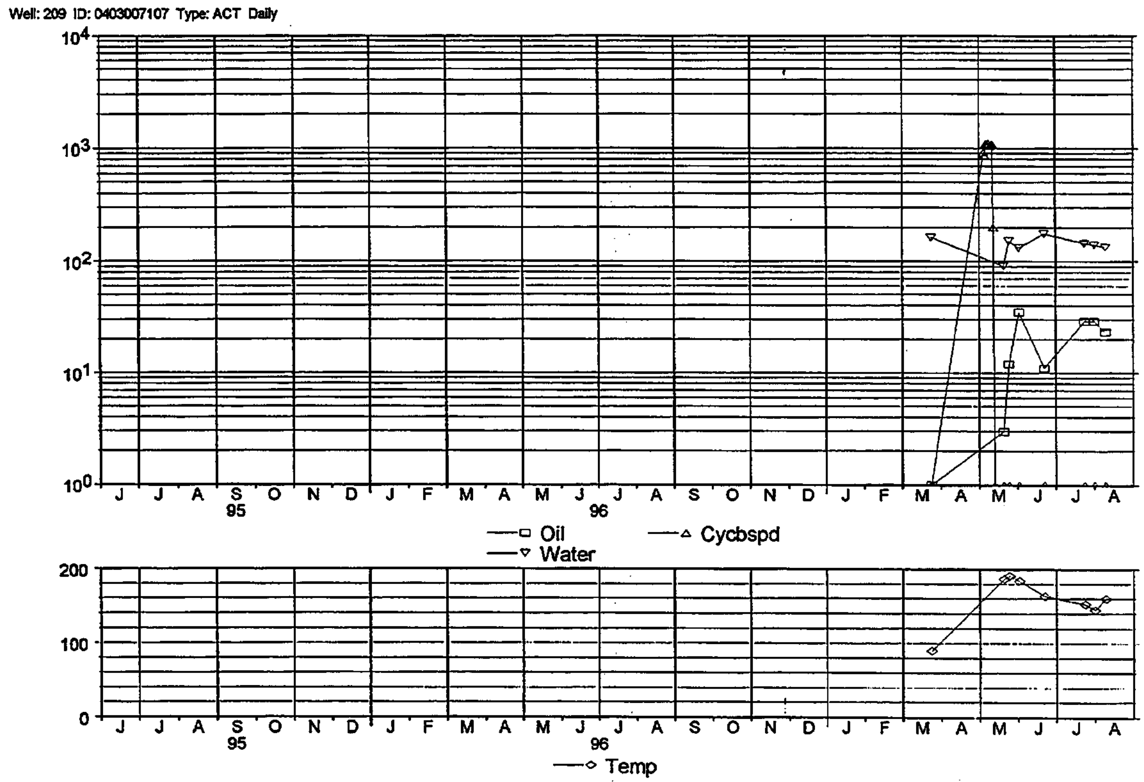

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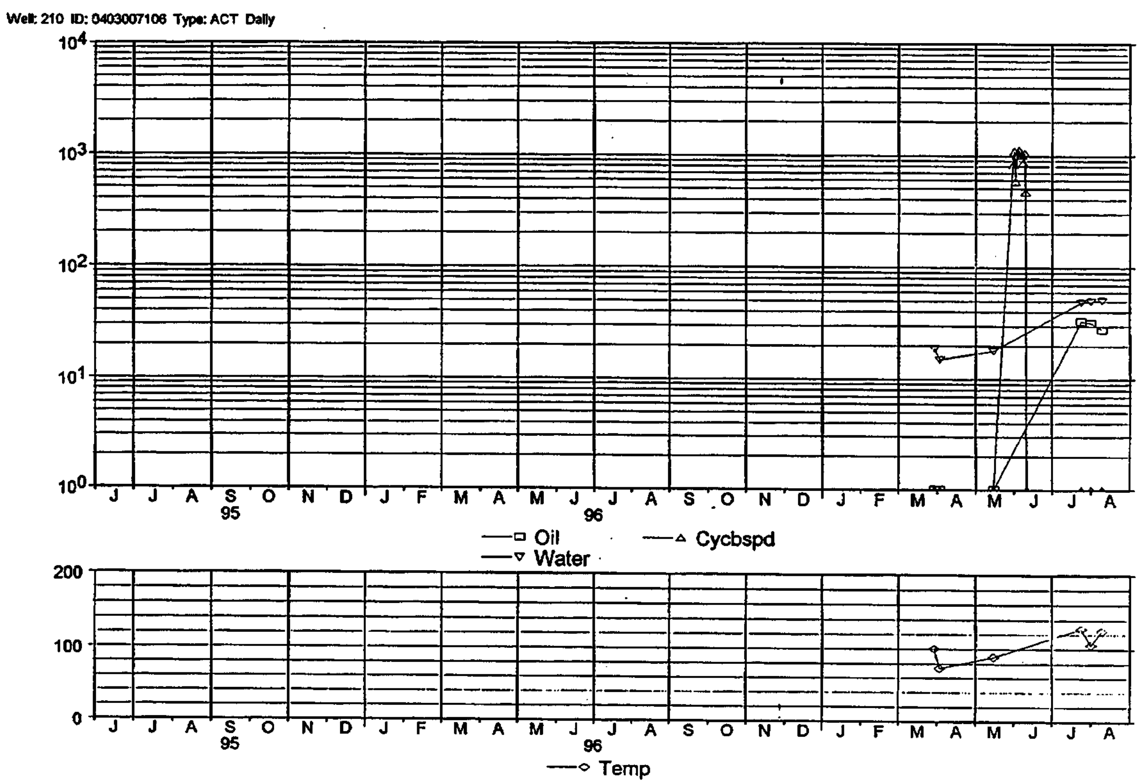

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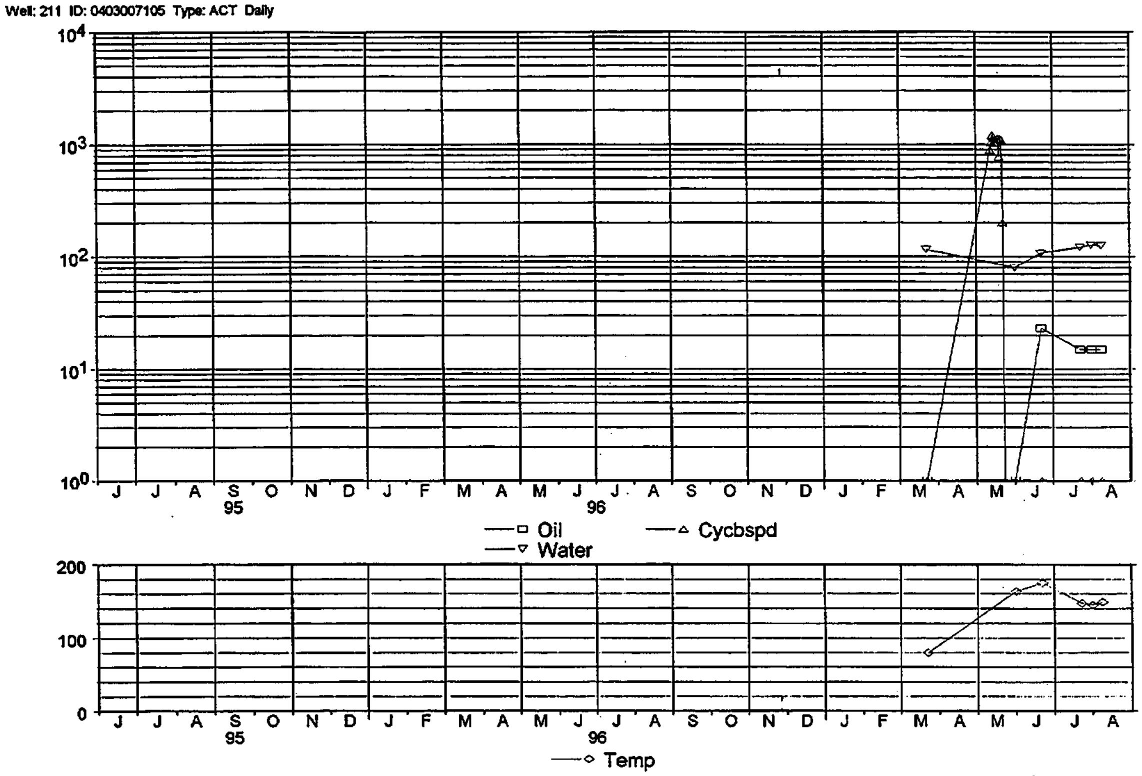
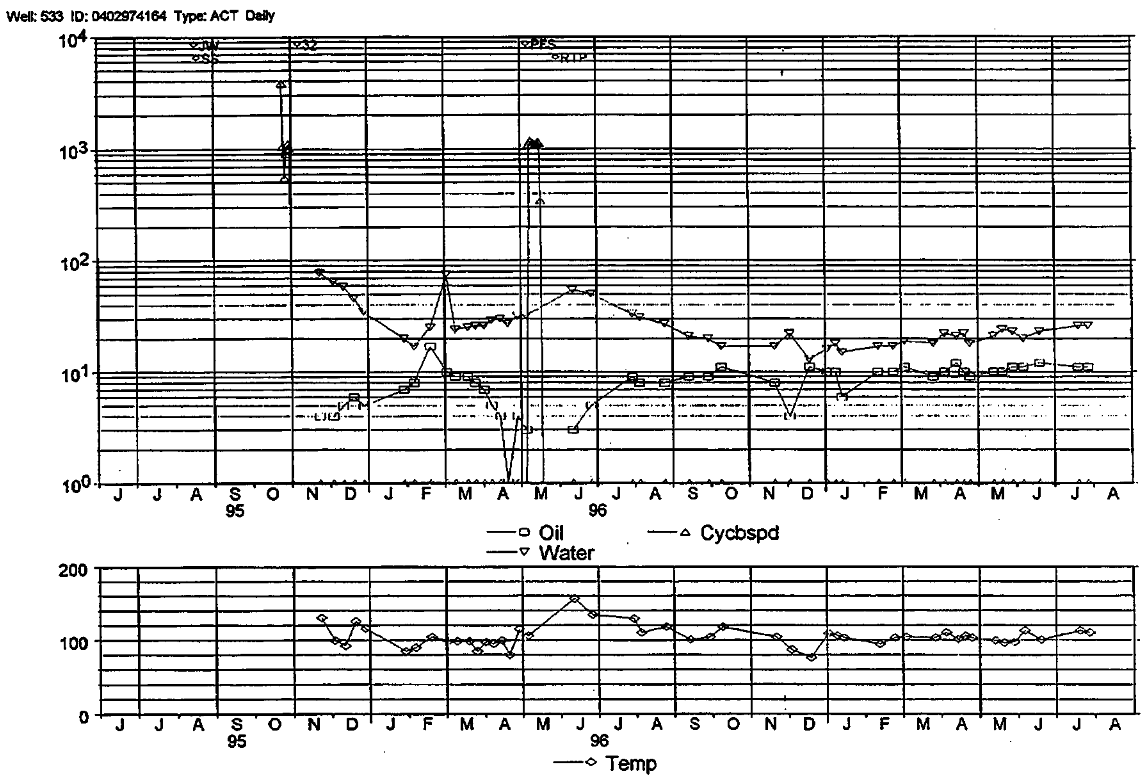
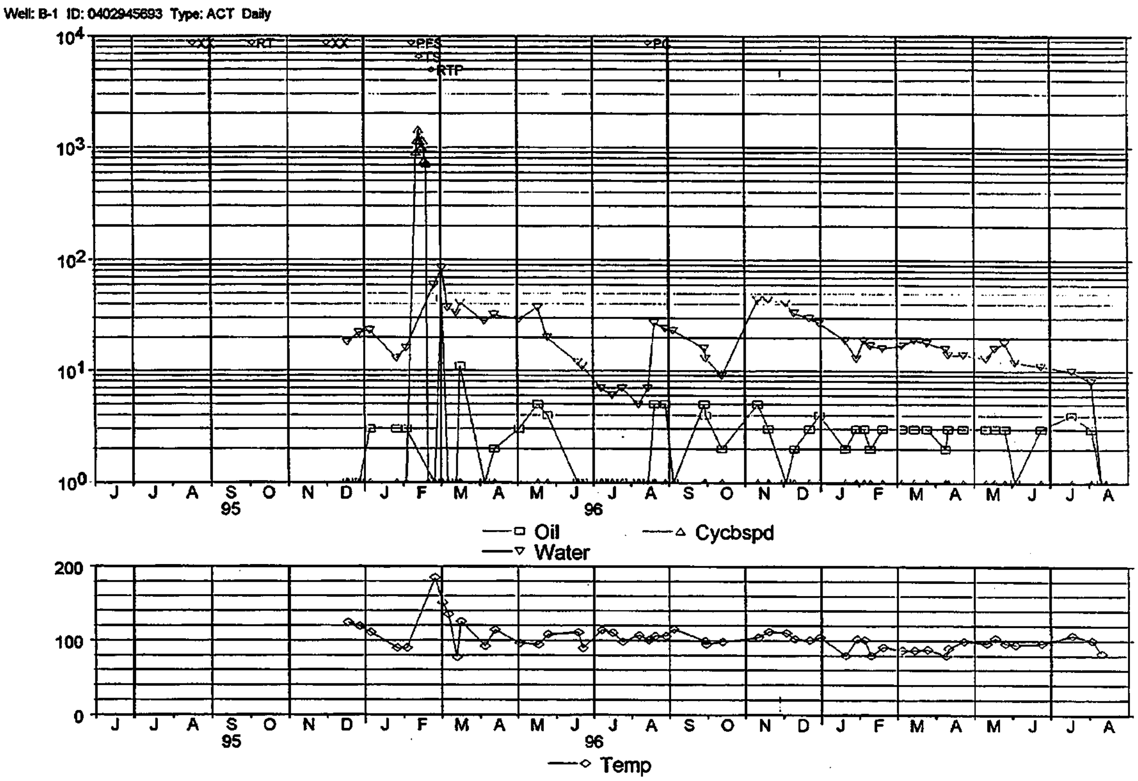


Pru 533



Pru B-1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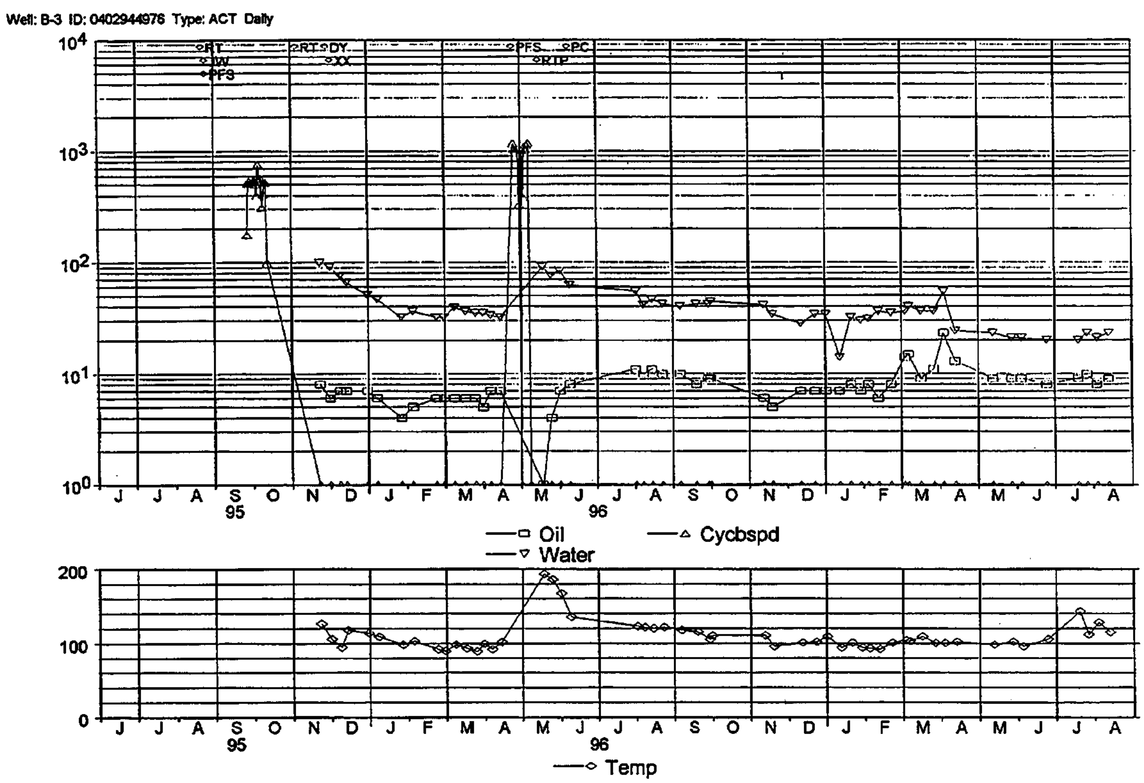
10^4
10^3
10^2
10^1
10^0
J J A S O N D J F M A M J J A S O N D J F M A M J J A
95
96
Oil
Water
Cycbspd
200
100
0
Temp

Pru B-3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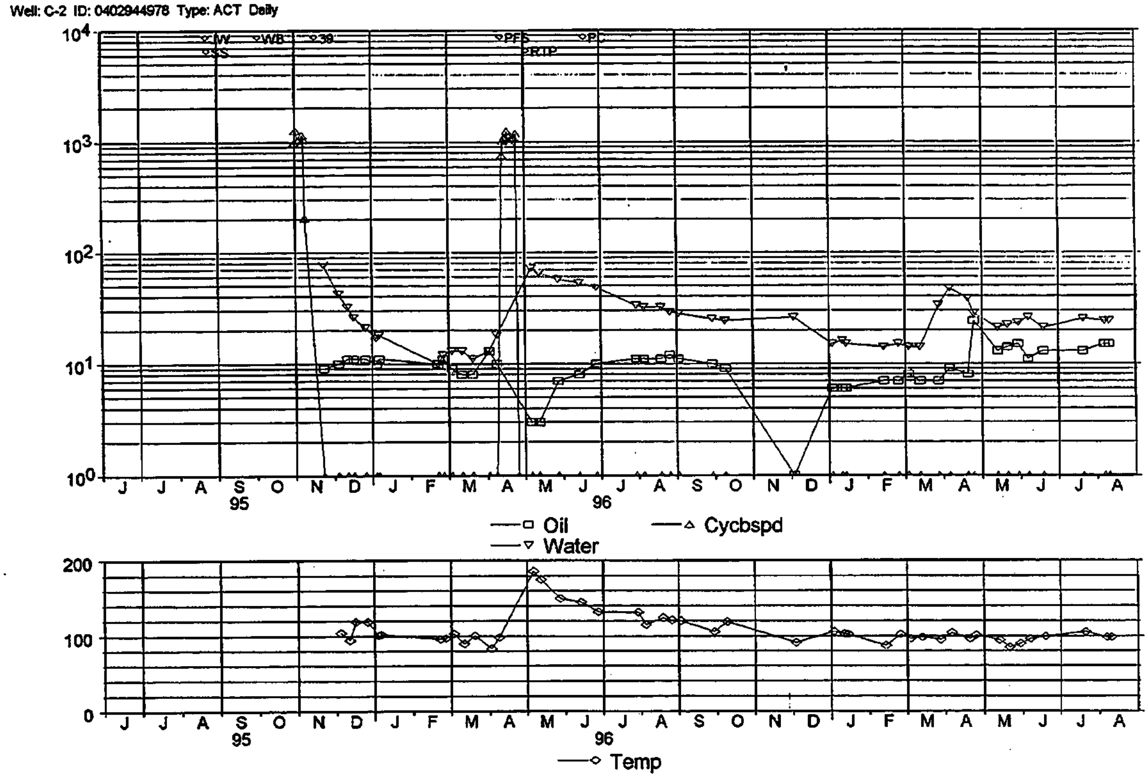
10^3
10^2
10^1
10^0
J J A S O N D J F M A M J J A S O N D J F M A M J J A
95
96
Oil
Water
Cycbspd
200
100
0
Temp

Pru C-2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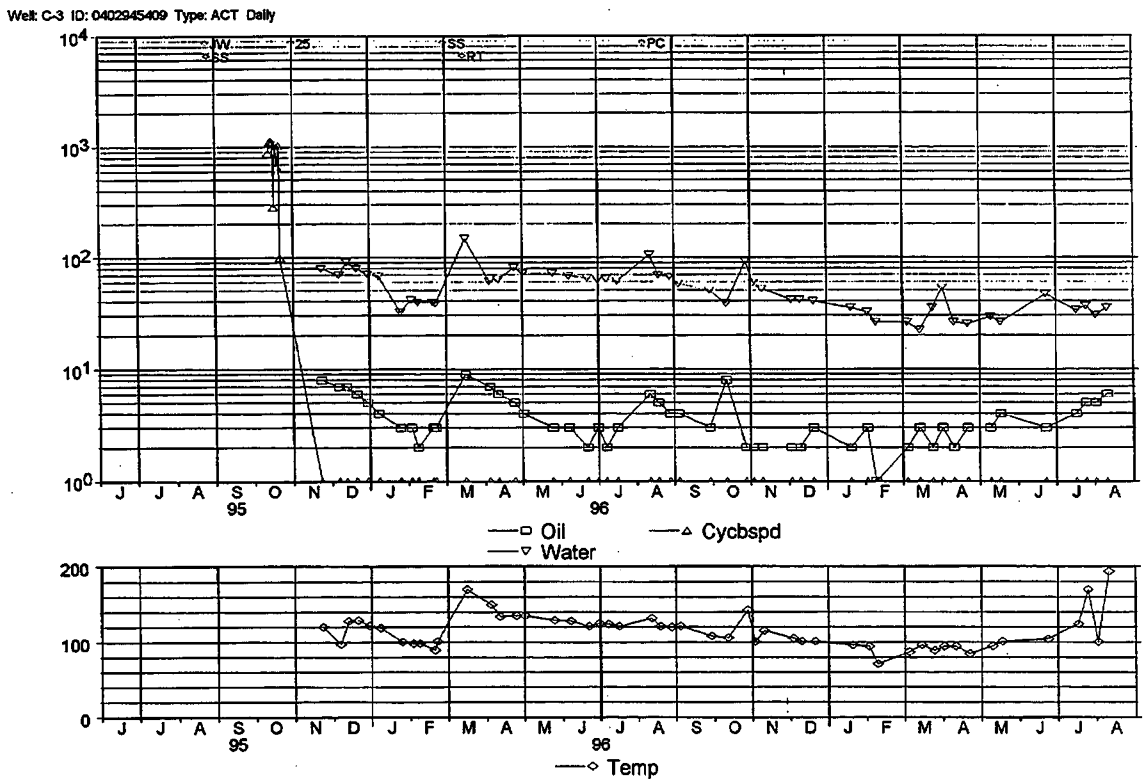
10^3
10^2
10^1
10^0
J J A S O N D J F M A M J J A S O N D J F M A M J J A
95
96
Oil
Water
Cycbspd
200
100
0
Temp

Pru C-3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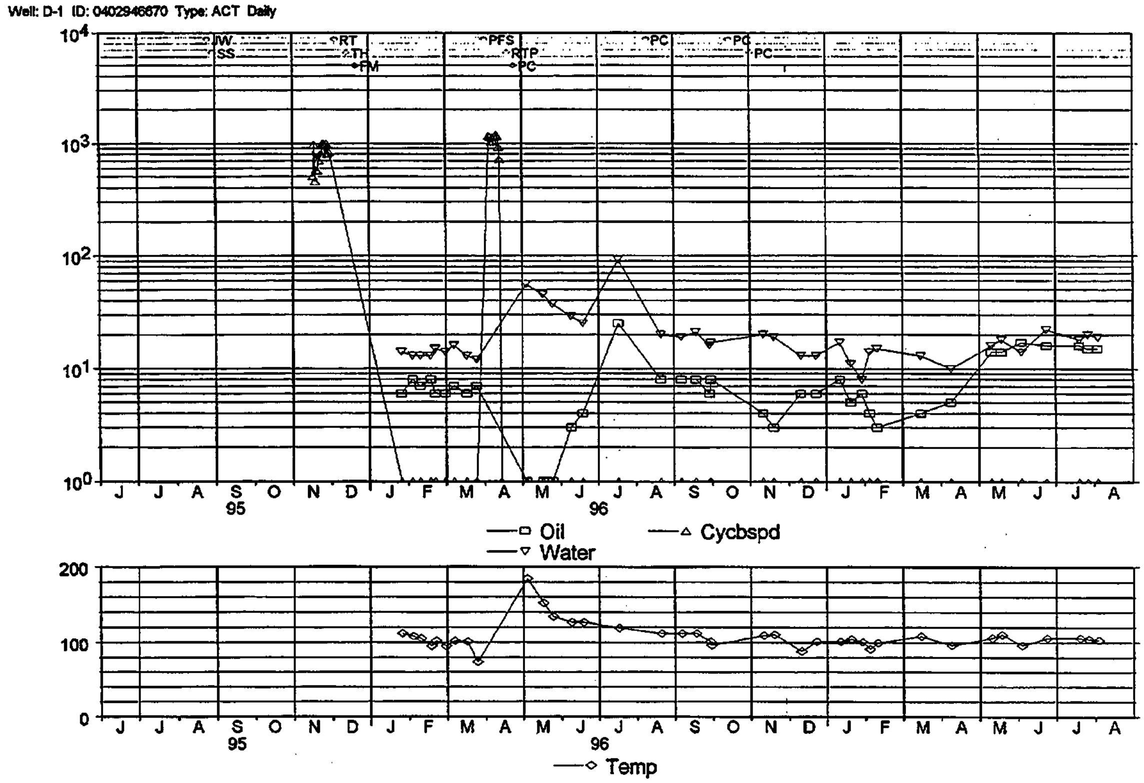
10^3
10^2
10^1
10^0
J J A S O N D J F M A M J J A S O N D J F M A M J J A
95
96
Oil
Water
Cycbspd
200
100
0
Temp

Pru D-1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10^3
10^2
10^1
10^0
J J A S O N D J F M A M J J A S O N D J F M A M J J A
95
96
Oil
Water
Cycbspd
200
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Temp

Chapter 6

Technology Transfer

Public Workshop

To present the technical results of the design phase of the project to as broad an audience of California-based operators as possible, a one-day public workshop was held in Bakersfield on December 5, 1996. The site of the public workshop was the Four Points Sheraton Inn, which is very convenient to the offices of most of the companies then operating in the Midway-Sunset and other fields in the southern San Joaquin Basin. The program covered the geology, lithologic characterization, geostastical modeling, and reservoir simulation of the Pru demonstration site. In addition, the results of the cyclic baseline testing and the plans for the demonstration phase were presented. To supplement the oral presentations, poster displays and segments of the Pru 101 core were available for inspection during the coffee/lunch breaks and at the end of the workshop.

There were about 55 registrants for the public workshop representing nearly all of the significant operators, large and small, in the Midway-Sunset Field. Jerry Casteel and Viola Rawn-Schatzinger attended representing the DOE National Petroleum Technology Office. Project team members presenting at the workshop were Steven Schamel, Creties Jenkins, Doug Sprinkel, Craig Forster, Milind Deo and Bob Swain.

To advertise the workshop, notices were mailed to about 300 persons identified on a mailing list provided by Mike Simmons of ARCO Western Energy and through an announcement in the newsletter of the San Joaquin Geological Society.

In conjunction with the public workshop, a PC workstation was purchased and loaded with data files and text related to the project. The public-access workstation was placed in the Bakersfield office of the California Division of Oil, Gas and Geothermal Resources in December 1996. The use of the workstation was demonstrated by Doug Sprinkel during the workshop. All project data can be examined and downloaded from this public-access site.

Conference Presentations

By invitation, members of the project team participated in the DOE-sponsored *Fourth International Reservoir Characterization Technical Conference* held in Houston, Texas, March 2-4, 1997. The paper entitled "Reactivation of an idle lease to increase heavy oil recovery through application of conventional steam drive technology in the Midway-Sunset Field, San Joaquin Basin, California" was published in the conference proceedings and presented as a poster.

At the 1997 annual convention of the American Association of Petroleum Geologists (AAPG) in Dallas, Texas, April 6-9, the project team presented an invited paper in the session *Results of Joint DOE/Industry Programs*. The poster paper entitled "Enhanced oil recovery in the Midway-Sunset Field, San Joaquin Basin, California: A DOE Class III Oil Technology Demonstration Project" summarized the purpose of the project and the technical results to date. By invitation, the same poster paper was presented at the annual meeting of the Pacific Section of the AAPG in Bakersfield, California in mid-May, 1997.

The goals and status of the project were presented at a DOE Contractors Conference sponsored by the National Petroleum Technology Office in June 1997. The week-long conference was held in Houston, Texas.

The project was featured in the newsletter directed towards the petroleum industry published by the Utah Geological Survey.

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Appendix 1

Statement of Work for Budget Period 2 (Demonstration Phase)

University of Utah
ARCO Western Energy
and the
Utah Geological Survey

Reactivation Of An Idle Lease To Increase Heavy Oil Recovery Through Application Of Conventional Steam Drive Technology In A Low Dip Slope And Basin Reservoir In The Midway-Sunset Field, San Joaquin Basin, California

SCOPE OF WORK

This project is reactivating an idle lease in the Midway-Sunset field, aided by an integration of modern reservoir characterization and simulation methods. Cyclic steaming has been used to re-establish baseline production, as part of the characterization carried out in the Budget Period I. In the second budget period, a continuous steamflood EOR demonstration project will be initiated in the Monarch Sand reservoir to test the incremental value of this method as an alternative to cyclic steaming. Other economically marginal Class III reservoirs having similar producibility problems will benefit from insight gained from this project. The objectives of the project are: (1) to return the shut-in portion of the reservoir to commercial production; (2) accurately describe the reservoir and the recovery process; and (3) to convey the details of this activity to the petroleum industry, especially to other operators in California, through an aggressive technology transfer program.

TASK II.1: DRILL 11 PRODUCERS, 4 INJECTORS & 3 OBSERVATION WELLS

<u>Subtask II.1.1: Stake Locations and Biological Survey</u>

Surface locations which will be acceptable for the reservoir development plan will initially be picked from the aerial photograph obtained in Budget Period I. The *reservoir/operations engineer* will then visit the site with the drilling foreman and environmental specialist to determine if there are any logistical or environmental concerns. If needed, acceptable alternative locations will be determined. An second opinion from an environmental expert also may be required. The final locations will be staked and a surveyor will survey the locations.

Subtask II.1.2: Well Plans, Permits and Cost Estimates

A well course will be determined from the surface and bottom hole locations. With input from the reservoir/operations engineer, the drilling engineer will confirm that the well course is reasonable and design a well plan including specifications for mud, bits, logging, cement, casing, liner, gravel pack, etc. From the well plan drilling a cost estimate will be determined. Applications, reflecting the final well plan, will be submitted to obtain required permits.

Subtask II.1.3: AFC Preparation and Approval

The drilling cost estimate will be integrated with the facilities cost estimate for a total capital cost. A projected oil rate and reserves will be combined with the capital and operating cost estimates to forecast the internal economics of the project. A description and justification of the project will be presented along with the economics in an AFC for ARCO management approval, and to establish an internal cost tracking mechanism.

Subtask II.1.4: Drill and Complete Wells

Following the pilot pattern configuration determined to be optimal in the Budget Period I study, we will drill eleven producers, four steam injectors and three observation wells. The producers are currently planned to be gravel-packed slotted-liner completions, with the completion intervals determined from Budget Period 1 stimulation sensitivities. Steam injectors will be selectively perforated based on simulation results to optimize vertical sweep efficiency. The observation wells will be completed with casing of sufficient diameter to accommodate the logging tools (temperature and neutron) needed for flood surveillance. Well plans will be designed to ensure safety of personnel and the environment.

A typical well plan will involve an ARCO onsite representative (*drilling foreman*) and a number of subcontractors who will provide the required equipment and material.

Subtask II.1.5: Equip New Wells

Rod pumping units, flowlines and CVCS lines will be purchased and installed on the new producers. Also downhole lift equipment such as tubing, rods and pumps will be installed.

TASK II.2: INSTALL LEASE PRODUCTION AND INJECTION FACILITIES

Subtask II.2.1: Expand Production Header

The existing Pru production header will have to be expanded to accommodate the additional producers to be drilled in Subtask II.1.4. This subtask includes the design, purchase and installation of this equipment.

Subtask II.2.2: Install Steam Header and Distribution Lines

A steam header and distribution lines will be designed and installed to split steam to the four new steam injection wells to be drill in Subtask II.1.4. This subtask includes the design, purchase and installation of this equipment.

Subtask II.2.3: Install Production Flowlines

The new producers to be drilled in Subtask II.1.4 will need flowlines back to the production header. These additional lines will require new racks.

Subtask II.2.4: Install CVCS Lines

The new producers to be drilled in Subtask II.1.4 also will need CVCS lines back to the Kendon #1 compressor site. These additional lines will require new racks.

Subtask II.2.5: Equip Steam Generator with Low NOx Burner

By 1998, environmental regulations will require the addition of a low NOx burner to the existing steam generator at Pru to meet emissions limits. This subtask includes the design, purchase and installation of this equipment.

TASK II.3: MONITOR STEAMFLOOD PILOT

Subtask II.3.1: Inject Steam

A total continuous rate of 1100 BSPD will be injected into the four steam injectors in the pilot area to implement the steam drive. This subtask will include the cost of fuel gas to be burned in the steam generator providing the required steam.

Subtask II.3.2: Produce Oil and Water

Many tasks are required to keep a heavy oil lease on production. The key personnel involved in this are the production supervisor and the lease operator. The *production supervisor* directs the activities of the operator, as well as other support functions such as electricians, mechanics, and construction crews, which may be needed from time to time to correct problems or help optimize the lease operation. The *lease operator* is the main person responsible for ensuring that the lease is performing at its best on a day to day basis. This individual puts wells in and out of test, records all production and injection data, and trouble shoots problems in the wells and production facilities. Information is passed on to the production supervisor who will assign tasks to the support personnel and/or well workover rig required to solve the problem.

Subtask II.3.3: Maintain Production & Injection Database/Graphical Displays

Production and injection data reaches the engineer via a computer network. The data is downloaded to the engineer's PC database every day. A commercial software is used to evaluate the data using graphical displays, including multi-axis graphs and areal bubble plots. The data is reviewed for facilities, individual wells and groups of wells. Trends may be observed which will indicate the need for remedial work or a change in the operating strategy.

Subtask II.3.4: Cased Hole Logs

In anticipation of potential problems with reservoir heterogeneity and associated channeling, the operations group will periodically run injection surveys to determine which zones are taking most of the injection fluids. Temperature and neutron logging data collected from the four temperature observation wells will be used to identify the pattern of steam migration and the regions of oil production. Baseline logs will represent the project starting point. Repeat logs will be run periodically to capture the project performance over time, as compared to the baseline logs and previous repeats. Observed trends may indicate the need for remedial wok or a change in the operating strategy

TASK II.4: UPDATE GEOLOGICAL CHARACTERIZATION

Subtask II.4.1: Fit new Wells into Stratigraphic Framework

Geologic and reservoir data will be collected from the new wells to provide baseline pre-demonstration information and to enhance interwell correlations made in Budget Period I.

Subtask II.4.2: Revise Subsurface Maps

The finalized maps described in Subtask I.1.4 of Budget Period I will be modified to include the data generated from the demonstration project.

TASK II.5: UPDATE RESERVOIR SIMULATION

Subtask II.5.1: Performance monitoring and model improvement

Injection and production data from the pilot monitoring, Task II.3, will be applied to the reservoir simulation model developed in Budget Period I. As the pilot flood progresses, field results will be used to update and calibrate the reservoir simulator to improve reservoir management. Unexpected trends in the demonstration response will be incorporated into the simulators so that more accurate predictions of later trends can be made. A series of additional model runs will be performed in an effort to mimic the course of the pilot flood and to predict the future response of the reservoir to both short and long term steam drive production. The simulation update will be repeated at least twice at a later point in time to include additional actual reservoir performance. This activity will be performed on the half-acre symmetry element that was modeled in Budget Period I.

Subtask II.5.2: Reservoir simulation at different scales

Reservoir performance at various scales will be examined. In the current approach, the performance of the half-acre element was *extrapolated* to the 8-acre pilot scale and eventually to the 40-acre lease scale. Using geostatistical models at larger scales, the model will be systematically *expanded* to 8-acres and one or two simulations of the entire 40-acre lease will be performed, at least at a coarser resolution.

Subtask II.5.3: Process optimization

Results of simulations performed in Budget Period I helped identify the injection and production completion intervals, production rates, etc. for economic exploitation of the reservoir. A more systematic optimization of all relevant operational paramenters, based on well-defined objective functions, will be performed.

TASK II.6: TECHNOLOGY TRANSFER OF DATA AND INFORMATION

Subtask II.6.1: Industry Workshop in Bakersfield

Near the close of the project, a two-day workshop will be held in Bakersfield, California to present the final results of the Pru Fee demonstration to the operators in the San Joaquin Valley and elsewhere. Workshop presentations will be made by members of the project team, who will discuss the implementation and significant outcomes of the demonstration project. Although we are targeting operators in the San Joaquin Valley, the workshop will be open to the petroleum community in general.

Subtask II.6.2: Publish Technical Data and Results

All aspects of the project findings will be published to ensure the information derived from and insights acquired through the "case study" are available to the industry. Efforts will include publishing interim and final results through the DOGGR/UGS and technical journals. Technical talks and poster displays will be submitted to regional and national AAPG and SPE meetings near the end of Budget Period II. In addition to governmental publications, all team members will be encouraged to submit papers to professional journals.

The public-access DOGGR and WWW project database set up in Budget Period I will be updated to include information gained in Budget Period II.

Subtask II.6.3: Prepare and Present Displays at Industry Conventions

The Industry Outreach Program will include informational displays showing current status of the project at two major petroleum industry conventions each year.

Subtask II.6.4: Maintain Mailing List and Prepare Newsletters

The Industry Outreach Program will include newsletters sent to individuals and companies interested in the project. In addition, the newsletter will be "published" on public-access Web sites at the University of Utah (EGI), the Utah Geological Survey and elsewhere.

TASK II.7: PROJECT MANAGEMENT

Subtask II.7.1: Project Accounting

All invoices and time cards will be processed through the University of Utah to account for the costs associated with this project, as outlined by the statement of work. This task includes coding the charges to the correct tasks and tracking and reporting the costs to team members.

Subtask II.7.2: Project Coordination and DOE Interface

The project will be directed to ensure quality control, adherence to U.S. Department of Energy (DOE) and Federal guidelines, and the distribution of all deliverables on behalf of team members and subcontractors. This task includes coordination of the technical team, financial/business group, and contractor organization activities, as well as communication with appropriate DOE counterparts.

Subtask II.7.3: Project Reports

As per the requirement of the Cooperative Agreement, this task will include the preparation and delivery of the required technical and financial reports such as the quarterly progress reports, yearly progress reports, topical report, and a final project report. Team meetings will be held periodically as needed to keep the project on track.